OGCB REPORT 66-C

REPORT ON AN APPLICATION OF TRANS-CANADA PIPE LINES LIMITED UNDER THE GAS RESOURCES PRESERVATION ACT, 1956

JUNE, 1966

Alta

OIL AND GAS CONSERVATION BOARD
603 SIXTH AVENUE SOUTH WEST • CALGARY, ALBERTA

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II INTERVENERS

Interveners	Represented by	Abbreviation of name used in Report
City of Calgary	A. C. MacWilliams, Q.C.	Calgary
City of Edmonton	A. F. Macdonald, Q.C.	Edmonton
Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited	B. V. Massie, Q.C.	Utility Companies
Pan American Petroleum Corporation	G. E. Little	Pan American
Alberta Division of the Canadian Petroleum Association	D. W. MacFarlane	Alberta Division of CPA
Supertest Investments and Petroleum Limited	A. J. Miller	Supertest
Peace River Mining & Smelting Ltd.	C. P. Gravenor	Peace River Mining
Alberta and Southern Gas Co. Ltd.	R. A. MacKimmie, Q.C.	Alberta and Southern

III SUBMISSION OF TRANS-CANADA PIPE LINES LIMITED

In its application Trans-Canada asked the Board to amend the permit it now holds (Permit No. TC 64-6) by

(a) extending the term of the permit from October 31, 1989, to October 31, 1990,

(b) increasing the maximum volume of gas that may be removed in any consecutive twenty-four hour period by 445 million cubic feet to 1995 million cubic feet,

(c) increasing the annual volume of gas that may be removed by 140 billion cubic feet to 665 billion cubic feet,

(d) increasing the total volume of gas that may be removed during the term of the permit by 2.92 trillion cubic feet to 15 trillion cubic feet, (reduced at the hearing as discussed below from 3.23 trillion cubic feet and 15.31 trillion cubic feet respectively),

(e) adding to the list of pools, fields, and areas from which gas may be removed, Aerial, Athabasca, Bashaw, Bellis, Brownfield, Calling Lake, Corrigall Lake, Craigend, Crossfield, Equity, Figure Lake, Garrington, Ghost Pine, Lake McGregor, Little Bow, Malmo South, Marten Hills, Munson, Rolling Hills, Rowley, Sunnynook, Swalwell, Tawatinaw, Trochu, Vulcan and Wintering Hills,

(f) adding the North-east quarter of Section 11, Township 38, Range 1, West of the 4th Meridian, as another point

at which the applicant may take delivery of gas from the facilities of the Alberta Gas Trunk Line Company Limited and as a point at which it may measure gas for the purposes of the Permit.

At the hearing Trans-Canada stated that the results of drilling subsequently to the filing of its application had caused it to reduce significantly its estimate of reserves in the Marten Hills and Corrigall Lake areas, two of the areas it asked to have added to its permit. Since the estimate of reserves affects its application, Trans-Canada asked that its application be amended by reducing the total volume of gas it wishes to remove from 15.31 trillion cubic feet to 15 trillion cubic feet. The increase requested by Trans-Canada was reduced from 3.23 trillion cubic feet to 2.92 trillion cubic feet. The lower reserve estimate did not impel Trans-Canada to amend the other parts of its application.

The applicant has entered into an agreement with Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited, whereby the Utility Companies may purchase gas from Trans-Canada to meet their domestic, commercial, and estimated industrial requirements, and it has made arrangements with the same Utility Companies and with Plains-Western Gas & Electric Co. Ltd., whereby it makes gas available to serve certain small communities and farms within the Province.

Trans-Canada requested that the term of its present permit be extended by one year because the contracts it has recently signed for the purchase of gas are for a period of twenty-five

years, and although these contracts will extend beyond the date requested, in keeping with the "normal period of permit", it was asking for a twenty-five year permit.

Most of the additional volumes of gas Trans-Canada is requesting will be marketed in Eastern Canada and in the North-eastern United States. However, it has contracted to sell a portion of the gas to Saskatchewan Power Corporation in the vicinity of the Unity Field in Saskatchewan. The gas would be delivered through a pipe line to be constructed by The Alberta Gas Trunk Line Company Limited from its present facilities in the Provost Field to a point near the Alberta-Saskatchewan boundary. Trans-Canada will build the remainder of the line from the border to the Unity Field. In order that deliveries of gas may be accomplished in this manner, Trans-Canada asked that its permit be amended to provide for another point at which gas may be received from Trunk Line and measured before removal from the Province.

The Alberta Gas Trunk Line Company Limited has agreed to construct all the necessary pipe line facilities that will be required in Alberta to deliver the additional volumes requested by the applicant.

Reserves of Gas

After amending its estimates of reserves at the hearing, Trans-Canada estimated the remaining established reserves of gas in Alberta as of March 1, 1966, to be 38.2 trillion cubic feet, or the equivalent of 40.6 trillion cubic feet of 1000 Btu gas. The estimate represents an increase of

some 3.2 trillion cubic feet (1000 Btu basis) over the Board's December 31, 1964, estimate.

Trans-Canada submitted its estimate of reserves for each of the twenty-six areas it requested be included in its permit and for those fields now included in its permit in which its estimate of reserves are significantly higher than those published by the Board in OGCB Report 65-8[1]. The applicant also presented estimates of reserves for a number of other areas in which significant development took place during 1965 and the first two months of 1966.

Trans-Canada did not make a detailed review of the reserves of gas in the remainder of the fields and areas in the Province. It adopted the estimates made by the Board and published in its December 31, 1964, reserve report.

The following table summarizes the applicant's estimate of the remaining established reserves of gas as of March 1, 1966:

		Remaining Established Reserves (Trillions of Cubic Feet at 14.65 psia and 60°F)
Oil and Gas Conservation Board Estimate as of December 31, 1964		35.3
Increase		
In fields under contract to Applicant	2.7	
In other fields	1.2	
Total	3.9	

(1) Reserves of Gas, Natural Gas Liquids, Crude Oil and Sulphur, Province of Alberta, December 31, 1964.

Less Estimated Production December 31, 1964 to March 1, 1966	1.0	
Net increase	2.9	
Total reserves as of March 1, 1966		38.2
Total reserves on 1000 Btu basis		40.6

A detailed discussion of Trans-Canada's estimate of the reserves of gas in Alberta appears in Appendix A.

Deliverability

Trans-Canada presented deliverability studies showing that the maximum day and annual volumes it requested could be met from the fields tied in or to be tied in until about 1980. Thereafter, the reserves in the fields would not be capable of sustaining the maximum daily or annual volumes.

Trends in Growth of Gas Reserves

Using data published by the Board and its own estimates of reserves as of March 1, 1966, Trans-Canada determined that the growth of initial marketable reserves in the Province over the last two years has been 3.2 trillion cubic feet per year, and that the long term growth rate has been 2.6 trillion cubic feet per year.

Requirements for Gas

Trans-Canada did not prepare an estimate of the requirements for gas of persons in the Province. For the purpose of determining whether a surplus exists, Trans-Canada adjusted the estimates presented by the Board in its OGCB Report 64-11[2] to relate to

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(2) Report on the Applications of Trans-Canada Pipe Lines Limited and Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. November 1964.

the period 1966 to 1995.

Surplus

Trans-Canada presented a new method for calculating the reserves of gas surplus to the needs of persons in the Province and to the subsisting permit commitments. The method involves the separation of Alberta's thirty-year requirements for gas and the reserves necessary to supply them into two categories, present and future. The present or "contractable requirements" are those for which reserves of gas can now be contracted on a long term basis. The future or "remaining" requirements are those in excess of the contractable requirements which, because they will not materialize for some years, cannot now be contracted practicably.

The applicant contended that the reserves in excess of those needed to meet the contractable requirements and the subsisting permit commitments should be declared as surplus, called the "contractable surplus". The remaining requirements would be met from reserves of gas now deferred by reason of oil production, from appreciation of established reserves, from reserves to be discovered, and from a portion of the reserves now considered to be beyond economic reach.

The method as presented by Trans-Canada would be applied in the following manner:

(1) The contractable reserves would be determined by subtracting from the established reserves the reserves now considered beyond economic reach and those deferred by reason of oil production or

because the reserve is being cycled to prevent loss of natural gas liquids.

(2) The contractable requirements would correspond to the reserves in those fields now supplying Alberta's requirements plus an allowance for reserves which could now be placed under long term contract to supply the increased requirements expected by 1969.

(3) The reserves needed to meet the subsisting permit commitments would be 105 per cent of the original permitted volumes less production to date. Trans-Canada indicated that this is the relationship of the volumes it has been authorized to remove from the Province to the reserves it has under contract in the fields, pools, and areas listed in the permit.

(4) The difference between the contractable reserves and the contractable requirements and subsisting permit commitments would be considered as the contractable surplus.

(5) The remaining Alberta requirements would be balanced against the reserves expected from the appreciation of presently established reserves, from future discoveries, from reserves now considered beyond economic reach, and from those reserves now deferred. The amount of "remaining and future" reserves from these sources that could be considered as available to meet the remaining requirements, would be determined having regard to the circumstances at the time of assessment.

(6) The Board could grant an applicant authority to remove all of the contractable surplus as long as it was satisfied that

the remaining requirements could be met from remaining and future reserves.

Trans-Canada presented the following detailed calculations to illustrate the application of its method of calculating the gas surplus to Alberta requirements and the present permit commitments:

	Trillions of cubic feet at 1000 Btu per cubic foot		
Contractable Reserves			
Established reserves as of March 1, 1966	40.6		
Less: Now considered beyond economic reach	3.2		
Less: Now deferred	4.9		
Total Contractables Reserves		32.5	
Contractable Requirements			
Reserves in field now supplying Alberta requirements	5.4		
Allowance for purchases to meet 1969 (4th year level) requirements	1.0		
Permit Commitments	20.7		
Total Contractable Requirements and Commitments			27.1
Contractable Surplus			5.4
Remaining Requirements			
Reserves needed to meet Alberta's thirty-year requirements	17.4		
Less: Contractable Requirements	6.4		
Less: Deferred gas available within thirty years	4.4		
Total reserves needed to meet Alberta's remaining future requirements		6.6	
Remaining and Future Reserves			
To be provided from appreciation of established reserves, reserves now considered beyond economic reach, and future discoveries.		6.6	
Future deficiency			0
Overall Surplus			5.4

Trans-Canada contended that the Board could safely declare the contractable surplus of 5.4 trillion cubic feet surplus to Alberta's present or contractable and remaining requirements because,

(a) the presently established reserves will appreciate for several years from their date of initial discovery, and

(b) it is reasonable to expect, in light of the history in this regard, that the major portion of the 3.2 trillion cubic feet of reserves now considered beyond economic reach will become within economic reach during the thirty-year period, and

(c) substantial quantities of reserves will be discovered in the future in light of the historical trend which shows this rate of growth to be approximately 2.6 trillion cubic feet per year.

For comparative purposes, Trans-Canada estimated that the overall surplus using the method employed by the Board, would be 4.2 trillion cubic feet before the release of reserves required to protect the maximum day volumes specified in the subsisting permits and 6.8 trillion cubic feet after the release of these reserves.

A detailed discussion of the method of surplus calculation appears in Section V.

IV SUBMISSIONS OF INTERVENERS

City of Calgary

The City of Calgary registered as an intervener, but did not submit evidence or participate in the hearing.

City of Edmonton

The City of Edmonton presented a submission and participated in cross-examination.

In its submission, Edmonton stated that it did not oppose the removal from the Province of gas as such, but was concerned with the sources which Trans-Canada suggested would supply Alberta's future requirements. These were deferred reserves, reserves currently uneconomic, appreciation of established reserves and new discoveries. Edmonton endorsed the principle advanced by Trans-Canada of dividing the requirements of the Province into presently contractable and future requirements. Edmonton believed that appreciation of established reserves and new discoveries tended to be absorbed by future permits and thus did not become available to meet future Alberta requirements. As evidence for this proposition, it contended that the Trans-Canada application involved the designation of areas extending far beyond those containing currently established proven or probable reserves.

With respect to reserves now beyond economic reach, Edmonton believed that when such reserves had appreciated sufficiently to become economic, they may be contractable only to large permittees. Future discoveries were anticipated by Edmonton to

be located possibly at considerable distances from provincial markets and thus not economically contractable. The intervener suggested that a similar situation exists for some deferred reserves. Edmonton recognized that Northwestern Utilities, Limited had contracts with permittees, but was concerned with certain contract provisions, which might require Edmonton to absorb costs of transportation from more distant fields.

At the hearing, the witness for the intervener stated that it was not making a specific request, but rather attempting to bring to the attention of the Board the relationship between future Alberta requirements and future sources of supply, and in particular, was concerned as to the adequacy of reserves available to supply the Edmonton market over the long term.

Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited

The submission of the Utility Companies was divided into two sections: Alberta market requirements for gas for the period 1966 to 1995 and the method of determination of the Alberta surplus or deficit.

The Utility Companies considered two separate areas within Alberta in preparing their forecast of Alberta market requirements, excluding contingency allowances. These were the areas served by the Utility Companies' system, and the remainder of the Province.

A detailed forecast, based on population projections was prepared for the Utility Companies' service areas. Population

of the Calgary and Edmonton metropolitan centres was expected to grow in a linear manner until 1980, with the annual combined increase totalling 28,000, after which a growth rate of two and one-half per cent per annum was anticipated to prevail. For other communities within the service areas, a total increase of 5,500 per year was projected until such time that this increase represented a growth rate of two per cent, following which the two per cent rate was assumed to obtain for the remainder of the forecast period. Total population served by the Utility Companies thus was expected to rise from 934,500 in 1966 to 2,005,000 in 1995, representing an overall compound rate of growth of 2.67 per cent per annum.

Gas requirements for the domestic, commercial and basic industrial categories of use were derived by applying per capita consumption rates to the forecast of population. Domestic per capita consumption was postulated to remain at a constant rate for the entire forecast period; commercial and basic industrial per capita consumption was expected to increase until 1970, and to be constant thereafter. Provision for additional industrial consumption was made by a category "special industrial demand", embracing sixteen existing large industrial customers, the requirements for which were projected on an individual basis.

Requirements for the Utility Companies' system were forecast to rise from some 132 billion cubic feet in 1966 to some 265 billion cubic feet in 1995, with a thirty-year total of 6,036

billion cubic feet.

The projection of requirements for the remainder of the Province involved a distinction between the Peace River area, and other areas. Domestic, commercial and basic industrial requirements for areas other than Peace River were forecast to grow at a rate corresponding to the anticipated population increase for urban areas in the Utility Companies' system excluding the Calgary and Edmonton metropolitan areas. The category special industrial comprised twelve separate loads, each of which was individually appraised. Future requirements in the Peace River area were based on studies by Northland Utilities Limited, a company associated with the Utility Companies, which indicated a growth rate of five per cent until 1978 and three per cent thereafter as appropriate for domestic, commercial and basic industrial consumption. One special industrial load was estimated separately.

Requirements for the remainder of the Province were forecast to increase from some 57 billion cubic feet in 1966 to some 88 billion cubic feet by 1995, with a thirty-year total amounting to some 2,225 billion cubic feet.

Total Alberta market requirements included a contingency provision increasing by four billion cubic feet each year, commencing in 1968 and totalling 1,624 billion cubic feet, to allow for sales to new industrial customers and additional sales to existing loads not covered by the special industrial requirements. In addition, a special provision was made for

the requirements of Peace River Mining & Smelting Ltd. scheme of 2,072 billion cubic feet, being the amount indicated in that company's submission.

Total Provincial gas requirements were therefore forecast to rise from some 189 billion cubic feet in 1966 to some 607 billion cubic feet by 1995, with a thirty-year total of some 11,957 billion cubic feet.

The Utility Companies believed that additions would have to be made to their estimate of total requirements to reflect compressor fuel requirements and the extraction of natural gas liquids.

Peak loads were calculated by applying a 34.3 per cent constant load factor to total domestic, commercial and basic industrial requirements, and by individual assessment for special industrial consumption, the latter averaging 81 per cent in 1966 and 85 per cent by 1995. The total Provincial load factor was estimated to increase from 46 per cent in 1966 to 49.3 per cent in 1995.

The second part of the Utility Companies' submission related to the method used to determine whether or not a Provincial gas surplus exists. The companies endorsed the principle advanced by Trans-Canada of ensuring sufficient reserves are available for the immediate development of local markets. Further, the Utility Companies suggested that both the immediate and long term situations be satisfied before the Board permitted additional removal from the Province. The

method of surplus calculation advocated was designed to combine both approaches. Currently developed (contractable) reserves were matched against present permit requirements and present (contractable) Alberta requirements, the latter being defined as the greater of reserves presently contracted for purposes of meeting Alberta requirements or reserves equivalent to thirty times the current annual requirements. Future (remaining) requirements, being the difference between the Alberta thirty-year requirements and Alberta present (contractable) requirements, would be matched against (remaining and) future reserves, comprising "trend gas", deferred gas and gas reserves currently classified as uneconomic. In calculating present permit commitments, the Utility Companies believed the total of reserves in fields for which permits have been granted should be included. The difference between the total reserves in such fields and reserves under permit would not, in the Utility Companies' opinion, be available for local contracting purposes. The Utility Companies defined the Alberta gas surplus as the lesser of the current surplus, determined as the difference between present (contractable) gas reserves and present (contractable) requirements, or the total surplus, calculated as the sum of the current surplus and (remaining and) future reserves, less future (remaining) requirements.

The Utility Companies presented an example calculation to demonstrate their method, using for illustrative purposes Trans-Canada's data, as shown below.

Trillions of cubic feet at 1,000 Btu per cubic foot

Contractable Reserves:		
Established Reserves as of December 31, 1965		41.3
Less: Reserves presently beyond economic reach	3.2	
Deferred	5.0	8.2
Total Contractable Reserves		33.1
Contractable Requirements:		
Alberta Requirements - reserves in pools connected to local supply systems (minimum 30-year life index)	6.4	
Permit Commitments - reserves in permit pools (estimated at 110% of 19.6)	21.6	28.0
Contractable Surplus		5.1
Remaining and Future Reserves:		
Deferred gas available during 30 years	4.5	
One half of reserves presently beyond economic reach	1.6	
Two-year trends	5.2	11.3
		16.4
Remaining Requirements:		
Balance of Alberta 30-year requirements		11.0
Overall Surplus		5.4

On the basis of these figures, the surplus available for export, defined as the lesser of the contractable or overall surplus, would be some 5.1 trillion cubic feet.

The Utility Companies' manner of calculation of surplus and forecast of Alberta's requirements are discussed in Section V and Appendix C respectively.

Peace River Mining & Smelting Ltd.

Peace River Mining is engaged in developing a new patented process to extract iron powders from deposits the company has under lease in the Peace River region. In its submission, Peace River Mining stated that if the results of a pilot plant program were favourable, construction of a commercial plant would commence in the Spring of 1967. The plant was anticipated to be in operation by 1969 and would be designed to produce iron powders and a variety of steel sheet products.

Peace River Mining believes that economic recovery of the iron is substantially dependent on the availability of large supplies of gas at low cost, to compensate for the higher transportation cost incurred by the location of a plant in Alberta. Therefore, it requested that the Board ensure such supplies would be retained by the Province, and cited advantages which would accrue to Alberta from the possible development of an integrated steel industry.

A survey by Peace River Mining of the market for iron powder, rolled sheets and strips and alloy strip and powder indicated potential production would initially total 100,000 tons per year in 1970, rising to 1,000,000 tons per year in 1978 and reaching 2,500,000 tons per year by 1989. On the basis of a gas consumption figure of 66 thousand cubic feet per ton of iron powder to 1976 and 57 thousand cubic feet per ton thereafter, Peace River Mining anticipated gas requirements

for its process would total some 2,498 billion cubic feet over the period 1969 to 1999. At the hearing, the corresponding figure for the period 1969 to 1995 was stated to be 2,070 billion cubic feet.

Matters relating to the development of an iron-ore processing industry in the Peace River regions are further discussed in Appendix C.

Pan American Petroleum Corporation

Pan American presented a submission in support of Trans-Canada's application. The intervener contended that the application should be granted because,

(a) the volumes requested are surplus to the needs of persons in Alberta (and to the subsisting permit commitments),

(b) substantial benefits will accrue to the Government and the people of the Province,

(c) Pan American will have an opportunity of marketing its gas within a reasonable period of time, and

(d) the markets to be served may be lost if not served when available.

Pan American considered the method of calculating surplus submitted by the applicant to be reasonable. It contended that the Board's present method of utilizing only two years of trend gas "requires the industry to prematurely invest in the drilling of development wells in order to maintain a gas bank". Pan American submitted that the Board could safely use gas to be

discovered or developed during the next five to ten years in meeting the thirty-year requirements of persons in the Province.

Pan American submitted an estimate of reserves in the Marten Hills and Gold Creek areas - areas in which it has substantial holdings.

Pan American estimated that the Wabiskaw Formation in Marten Hills contains 622.5 billion cubic feet of marketable gas, 480 billion of which it considered proved and 142.5 billion probable. The intervener estimated the marketable reserve in the Wabamun Formation in Marten Hills to be 1579 billion cubic feet, consisting of 1167 billion proved and 412 billion probable.

Pan American considered that the Gold Creek area contains 760 billion cubic feet of marketable gas, consisting of 527 billion proved and 233 billion probable.

A detailed discussion of the estimates presented by Pan American appear in Appendix A.

The Alberta Division of The Canadian Petroleum Association

The Alberta Division of The Canadian Petroleum Association supported the application of Trans-Canada. It submitted that at December 31, 1965, there were some 38 trillion cubic feet of marketable gas reserves in Alberta, consisting of 33.4 trillion proved and 4.6 trillion probable. The Alberta Division of CPA considered its estimate of proved reserves of 33.4 trillion cubic feet to be ultra-conservative because the "Lahee" reserves method, which it used, is too stringent, and

was intended primarily as a method for comparing estimates prepared by different estimators. The method does not permit the calculation of probable reserves even though there is reasonable expectation that such reserves do exist. Furthermore, it does not permit the estimator to use his best judgment, which in many cases is based on factual data, as to the areal extent of an underground reservoir.

In view of the shortcomings of the method, the Alberta Division of CPA considered its estimate of 38 trillion cubic feet to be more realistic than the 33.4 trillion cubic feet obtained from the application of the precise requirements of the Lahee method. The intervener believed that even the 38 trillion cubic feet was conservative, because reserves already discovered would continue to appreciate in the years ahead. It presented detailed calculations to support its view that the marketable reserves discovered to December 31, 1965, will grow eventually to some 43 trillion cubic feet, after deducting production to the end of 1965.

With respect to the Board's method of calculating the reserves surplus to Alberta requirements and the present permit commitments, the Alberta Division contended that the degree of protection allowed for is excessive and the reliance placed on future discoveries is far too small. It suggested that if the present method of protecting the Alberta gas requirements is continued, the very minimum allowance for future additions to reserves should be equivalent to five

times the average annual trend since 1951.

The Alberta Division of CPA reiterated its contention that a lengthy delay in marketing gas would have a serious effect on the economics of discovering and developing a reserve. The present application will provide producers with an opportunity of marketing reserves now shut in because of the lack of market.

Supertest Investments and Petroleum Limited

Supertest supported the application of Trans-Canada. It presented a detailed estimate of reserves in the Craigend area, an area in which Supertest has substantial holdings, and one of the areas from which Trans-Canada wishes to remove gas. Supertest estimated that there were some 256 billion cubic feet of established marketable gas in five horizons in the Craigend area. Its estimate consisted of 227 billion cubic feet of proved reserves and some 58 billion cubic feet probable, of which one-half was considered established.

Supertest stated that if the application of Trans-Canada is granted, it will have waited seven years since discovery to market its reserves in the Craigend area. The intervener contended that any substantial additional delay in marketing its gas would have the effect of rendering the entire project uneconomic from its inception, and under such circumstances, it would be reluctant to undertake any additional gas exploration projects.

A detailed discussion of Supertest's estimate of reserves

is presented in Appendix A.

Alberta and Southern Gas Co. Ltd.

Alberta and Southern did not present a written submission, but did present oral testimony. Mr. S. R. Blair, Manager and Vice-President of Alberta and Southern, spoke to the applicant's proposal for calculating gas surplus to Alberta's needs and present permit commitments.

Alberta and Southern agreed with the overall principle advanced by Trans-Canada but disagreed with some of its details. There were three areas of disagreement - reserves beyond economic reach, deferred reserves, and the reserves necessary to meet subsisting permit commitments. Alberta and Southern's views with respect to these matters were:

(1) A portion of the reserves now considered beyond economic reach should be considered as now contractable. Mr. Blair contended that during the past several years, the gas in a significant number of the fields considered to be beyond economic reach has, in fact, been contracted for.

(2) The amount of gas shown by Trans-Canada to be deferred beyond thirty years should be reduced. Alberta and Southern contended that a portion of this gas will be available to supply markets in two to three years.

(3) Alberta and Southern submitted that the present permit commitments should be taken as the face value of the permits less production and not 105 per cent as

> suggested by Trans-Canada or 110 per cent suggested by the Utility Companies. Mr. Blair contended that none of the present permits gives permission to remove more gas than that specified in the permit.

These matters are discussed further in Section V.

V BASIS OF CONSIDERATION

Method of Calculating Gas Surplus to Alberta's Requirements and Existing Permit Commitments

Trans-Canada in its submission presented for the Board's consideration a new method of calculating the gas surplus to Alberta requirements and the existing permit commitments. The main feature of the method proposed by Trans-Canada is the segregation of both the supply and requirement quantities into a "contractable" component and a "remaining future" component. In the Trans-Canada proposal, if the contractable reserves should exceed the contractable Alberta requirements plus the permit commitments, this quantity would be termed a contractable surplus. Trans-Canada suggested that the contractable surplus could then be declared surplus to the Provincial needs if the Board is satisfied that the additional or remaining future requirements of the Province could be met from deferred reserves, appreciation of established reserves and from reserves yet to be discovered.

The City of Edmonton, in its submission, stated that it believes the method of calculating the surplus proposed by Trans-Canada is sound, since it shows which of the general categories of reserves will be used to satisfy each portion of Alberta's future requirements. The Utility Companies also supported the principle of the Trans-Canada proposal. However, in their submission, they suggested certain additions to and modifications of the proposed method. Alberta and Southern,

in its submission, also supported the Trans-Canada proposal but suggested certain modifications in the details of the calculation.

The Board has previously considered a similar proposal made by Alberta and Southern as part of an application heard by the Board in July, 1964. The proposal was at that time unsupported by others. The Board, although it recognized certain merits in the proposal of Alberta and Southern, did not adopt it and in its OGCB Report 64-11[1] gave several reasons for its decision. A major reason given by the Board was that the categorization of reserves and requirements would create the possibility of a surplus occurring in the contractable category which might be removed from the Province despite the existence of a deficiency in the non-contractable category. This criticism of the Alberta and Southern proposal seems to have resulted from a misunderstanding and according to Mr. Blair's testimony at the recent Trans-Canada hearing, it had been Alberta and Southern's "expectation that there would only be export authorized if there were a surplus both in present terms and future terms". The Trans-Canada proposal is clear that it intends authorization of the removal from the Province of a contractable surplus only when the Board is convinced that the future requirements can be satisfied.

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(1) Report on the Applications of Trans-Canada Pipe Lines Limited and Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. November, 1964.

1. Current Board Method

The Board currently uses a combination of illustrative deliverability schedules and the "formula" method for assessing the gas surplus to Alberta's thirty-year requirements and existing permit commitments. A detailed discussion of the formula and its use was included in Appendix E of OGCB Report 64-11.

In the surplus calculation, the Board includes as available reserves, those reserves now considered within economic reach plus a fraction, calculated each time, usually one-half of the reserves currently considered beyond economic reach, less those reserves from which production will be deferred beyond the thirty-year period being studied. The Board also includes as available reserves the growth of gas reserves expected over a two-year period. In calculating this growth figure, the Board uses the lesser of the actual growth in reserves over the previous two years or two years of growth at the long term growth rate.

The Board then compares the total available reserves to the reserves needed to meet Alberta's requirements and the remaining permit commitments and, in this manner, determines whether a surplus exists on a thirty-year basis.

In determining the total gas needed to meet Alberta's thirty-year requirements (including terminal year peak gas), illustrative deliverability schedules are prepared for those fields connected to and supplying Alberta's requirements. The

deliverability schedules are not normally published by the Board. The schedules are used to estimate that portion of the connected reserves which will be produced during the thirty-year period and the peak day delivery which the remaining connected reserves will be capable of sustaining. These quantities are then subtracted from the estimated total thirty-year requirements and the terminal year peak day requirements to determine the amount of gas that must be delivered and the terminal year peak day delivery that will be required from other sources. The actual quantity of gas necessary to provide for these deliveries and the terminal year peak day is then calculated using the formula method. In this calculation it is assumed that the gas will come in part from established gas reserves not now committed to local utilities nor authorized for removal from the Province and in part from gas reserves not yet developed. For this reason the Board uses in the calculation, factors which reflect the delivery characteristics of all of the gas reserves in the Province. The sum of the connected reserves plus those reserves required from other sources represents the total amount of gas needed to meet Alberta's thirty-year requirements.

The Board currently uses the formula method in calculating the reserves required to meet existing permit commitments. Until recently it was the Board's practice to provide in this calculation for the terminal year peak day requirement. However, it should be stressed that the Board does not consider

the gas needed to protect for this terminal year peak as a firm permit commitment. In fact, the most recent permits issued by the Board have not specified a terminal year peak but rather have indicated that the quantity to be removed in the final years of the permit will be limited by field productivity and good engineering practice. In these cases, the Board has not, in its calculation, provided gas reserves for the terminal year peak day requirement, and it is not a part of the Board's current method to do so.

2. Views of the Board

The Board, in the light of the evidence presented by Trans-Canada and interveners at the recent hearing, has carefully considered the method it currently uses for assessing whether or not a surplus of gas exists in the Province. The method currently in use matches only the year by year requirements against the total available reserves and does not incorporate a test to evaluate the ability of the local utility companies in the first few years of the period under study to negotiate and contract for future supplies of gas. On the basis of the evidence presented at the hearing, the Board concludes that a method of assessment which would focus on the established gas available for immediate contracting to meet Alberta requirements is desirable and would to some extent afford a greater degree of protection to local consumers of gas. For this reason, the Board has decided to accept the categorization principle suggested by Trans-Canada, although it is not

prepared to accept outright all of the details of the proposed method of assessing the surplus situation.

The Board, having regard to the evidence of Trans-Canada, the Utility Companies, the City of Edmonton and Alberta and Southern, and also to its own knowledge and past experience in these matters, has formulated a new method of determining the gas surplus to Alberta's requirements and the existing permit commitments. The detail of the new method to be used by the Board for calculating the surplus and the reasons for the method are set out in the following discussion.

Contractable Reserves. Trans-Canada suggested that the contractable reserves be taken as the reserves now considered within economic reach less those reserves which are deferred by reason of oil production or location. The Utility Companies agreed with this part of the Trans-Canada proposal. Alberta and Southern suggested that a fixed portion, such as one-half, of the reserves presently considered beyond economic reach plus any reserves which are deferred for only a few years should also be included in contractable reserves. Mr. Blair, testifying on behalf of Alberta and Southern, argued that reserves which are classified by the Board as beyond economic reach or as deferred are often contracted for within a few years. The Board recognizes that this situation will frequently occur but believes it can be properly handled by shifting reserves from beyond economic reach or deferred to the contractable category when appropriate. Consequently,

the Board has adopted the Trans-Canada suggestion and will include in contractable reserves only established reserves currently considered within economic reach less those reserves from which production will be deferred for any reason.

Total Alberta Requirements. As mentioned previously, the Board currently uses a combination of illustrative deliverability schedules and the formula method in determining the total gas needed to meet the thirty-year Alberta requirements including the terminal year peak. Neither Trans-Canada nor any of the other registered parties at the hearing suggested modification of this. In fact, when questioned, Mr. Horte, testifying on behalf of Trans-Canada, stated that he believed the calculation as currently carried out by the Board to determine the amount of reserves needed to meet the thirty-year requirements is "a reasonable approach". Accordingly, the Board will continue to calculate the total Alberta requirements in the manner outlined earlier in this section of the report.

Contractable Requirements. Trans-Canada suggested that the contractable Alberta requirements reflect the amount of gas remaining in those fields currently supplying Alberta's requirements plus an allowance to permit Alberta utility companies to purchase gas to meet the anticipated growth in requirements for a few years into the future. Alberta and Southern endorsed this suggestion, but the Utility Companies proposed a modification whereby the contractable requirements

would be taken as the greater of thirty times the requirements of the first year of the period under consideration or the remaining reserves in those fields committed to and supplying Alberta's requirements. Both of the above suggestions with respect to contractable Alberta requirements are somewhat arbitrary, and the Board has considered along with these suggestions, several other arbitrary definitions, such as twenty times the requirements of the fourth year. The Board has concluded that since the method suggested by the Utility Companies gives results similar to the Trans-Canada suggestion but is simpler and more specific, it is the better method and has therefore adopted it.

Permit Requirements. Trans-Canada suggested that the permit requirements be taken as 105 per cent of the original permit quantities less the quantity removed to date. The 105 per cent was selected as an estimate of the reserves needed under contract in order to produce the quantities authorized for removal from the Province during the term of a permit. Alberta and Southern suggested that the permit requirements be taken as the remaining permit commitments without expansion to 105 per cent. On the other hand, the Utility Companies argued that any excess of gas reserves in fields included in a permit over those quantities set out in the permit are not actually available for local requirements and the allowance for permit requirements should be the total of the remaining reserves in the permit fields. The Board does not agree with

the Utility Companies and believes that in many circumstances gas reserves not under contract but in a field included in a permit might be bought to meet local requirements. In fact, only those quantities of gas actually set out in a permit are committed for removal from the Province and as a result, the Board has decided to adopt an approach similar to that suggested by Alberta and Southern whereby the permit commitments will be taken as the remaining permit commitments without further expansion. However, in spite of the formal limitations of the permit where, because of an earlier Board policy, calculations published by the Board have included some quantity of gas to provide for the terminal year peak day, the Board will retain this quantity as part of the permit requirement. For new permits or amendments to existing permits the Board will provide for only those quantities set out in the permits. The amount of terminal year peak gas which the Board will recognize happens at this time to be in the order of 5 per cent of the total remaining permit commitments. However, the amount as a percentage of the total commitments will probably become less with time, particularly if future permits or amendments to permits include periods of declining deliveries. This type of permit will serve to increase the total remaining permit commitments while reducing the amount of terminal year peak gas for which the Board is prepared to provide.

Remaining Requirements. Trans-Canada suggested and

Alberta and Southern and the Utility Companies agreed, that the remaining Alberta requirements be taken as the total gas needed to meet Alberta's thirty-year requirements less that portion of the requirements classified as contractable. Trans-Canada actually proposed a slight variation in this method in that the deferred gas which will become available within thirty years was to be deducted from the remaining Alberta requirements. The Board believes it more appropriate to use this deferred gas as part of the future reserves and, since this would make no difference in the results of the calculation, the Board has adopted as the remaining Alberta requirements the total gas needed to meet Alberta's thirty-year requirements less the reserves classified as contractable.

The Board has also considered whether or not it should continue the policy used in its most recent reports whereby it has split the remaining Alberta requirements into that portion which must actually be delivered for use during the thirty-year period and that portion which is only needed to sustain the peak day requirements in the terminal year. Because such a split gives a better picture of the remaining Alberta requirements and because it would permit the use of alternative means for providing for the peak gas, such as the use of a greater amount of anticipated growth of reserves, the Board believes it should continue its policy of separating the remaining Alberta requirements.

Remaining and Future Reserves. Trans-Canada suggested

that the Board should give weight to the expected growth in gas reserves and to those reserves beyond economic reach, in deciding whether the remaining Alberta requirements could be satisfied. (As was noted earlier, Trans-Canada in its proposal subtracted the deferred gas expected to be available within thirty years from the remaining Alberta requirements.) Trans-Canada did not specifically recommend that the growth in reserves for a certain number of years be considered or that a set fraction of the reserves currently beyond economic reach be considered but stated that the Board should review the matter in the light of the situation at the time of the review. Mr. Horte, testifying on behalf of Trans-Canada, did state that, in his opinion, the Board could place greater reliance on future discoveries than it is now doing. Alberta and Southern did not offer any modifications to this part of the Trans-Canada proposal. The Utility Companies suggested that the Board should maintain its existing policy of using only two years growth of gas reserves and a fraction of reserves now classified as beyond economic reach in appraising the future surplus.

The Board has carefully considered what reliance should be placed on future reserves to satisfy Alberta's remaining requirements.

To protect those requirements for gas which will actually have to be delivered (i.e. other than gas required to meet the thirtieth year peak deliveries), the Board

believes the current policy should continue unchanged. The Board is prepared to consider only the following as future reserves:

(a) the growth in reserves anticipated over a two-year period,

(b) that portion of reserves now beyond economic reach which it believes will be available within the thirty-year period, and

(c) those deferred reserves which it believes will be produced within the thirty years.

To provide for the reserves of gas necessary to provide deliverability to meet the thirtieth year peak requirements, often called cushion gas, the Board believes some modification of its current policy is desirable. The Board recognizes that such requirements differ substantially from the other remaining requirements in that a substantial portion of the cushion gas requirements may be satisfied by alternative methods. The Board's estimate of cushion gas is a maximum in that its calculation incorporates conservative assumptions. The deliverability schedules have been based upon drilling densities ranging from one to four sections per well. No storage fields other than those now in use have been assumed. Minimal additional field compression facilities have been assumed. The cushion gas requirement may be reduced by the adoption of closer spacing than assumed by the Board, by the greater use of underground storage and by the addition of more compression

facilities. The Board, therefore, has decided that it would be proper, in view of these considerations and the stage and excellent history of reserve growth, to give weight to more than the two-year growth in reserves when considering the cushion gas protection.

In considering the portion of the cushion gas that may be met from the growth in reserves beyond the two-year period the Board does not believe it desirable to adopt a fixed quantity nor a set number of additional years growth in gas reserves. Rather, it will have regard to the long term growth rate of gas reserves, the number of years of growth at this rate that would be required to satisfy the portion of the requirement not otherwise met, the percentage of the apparent ultimate reserves of the Province that have already been developed, the likelihood that the peak day requirements would to some extent be supplied by other means, and any other matters of relevance.

3. Summary

In the actual consideration of an application for a permit authorizing the removal of gas from the Province, the Board will assess the availability for the purpose of the application of a surplus, by the following steps:

1. The existence or otherwise of a contractable surplus will be determined through a comparison of

(a) the contractable reserves, being the established reserves within economic reach less any reserves

deferred for reasons of oil production or cycling, and

(b) the total of the contractable Alberta requirements and the remaining permit commitments.

2. The existence or otherwise of a future surplus will be determined by evaluating

(a) the remaining Alberta requirements, and

(b) the remaining and future reserves determined as the portion of the reserves presently beyond economic reach which the Board estimates will be within economic reach within the thirty-year period, the portion of the deferred reserves which the Board estimates will become available within the thirty-year period, and the growth of gas reserves anticipated over a two-year period.

3. In the event that the remaining Alberta requirements exceed the remaining and future reserves, the Board will have regard for the fact that the cushion gas portion of the remaining Alberta requirements is a less definite requirement for gas and will consider the significance of any deficiency in the meeting of this portion of the requirement in the light of the factors previously discussed and the number of additional years of growth of gas reserves which would be required to overcome the deficiency.

4. Where the Board is satisfied that there is a contractable surplus adequate to meet part or all of the requirements

of an application for removal of gas and where there is also a future surplus or a future deficit not exceeding the amount of the cushion gas which could, in the Board's opinion, be met by a reasonable additional number of years of growth of gas reserves, the Board would authorize the removal of gas from the Province.

The modified method of assessing the contractable surplus and the future surplus is discussed further and illustrated in detail in Appendices D and E.

Volume of Gas under Contract to Trans-Canada

The Board believes that an applicant should have under contract in the order of 80 per cent of the total volume of gas it wishes to remove from the Province. Furthermore, it should have under contract a substantial portion of the gas in each of the fields or areas it wishes to be included in a permit.

These are not new requirements, rather they are a statement of the policy the Board has followed in previous applications.

The Board has examined Trans-Canada's application with these requirements in mind. It finds that Trans-Canada has under contract over 95 per cent of the Board's estimate of the reserves underlying the lands the applicant has requested be included in its permit. Also, with the exception of two small areas, Trans-Canada has under contract in each of the fields and areas requested an adequate portion of the reserves as estimated by the Board, the exceptions, in the Lake McGregor

and Brownfield areas, involve some 6 billion cubic feet of gas, no portion of which is under contract to the applicant. The Board does not think it proper to include these reserves in any permit that may be issued.

Other Amendments requested by Applicant

1. Extension of the Term of the Permit

(1) Views of Trans-Canada

Trans-Canada's application asks that the termination date of the permit be changed from October 31, 1989, to October 31, 1990, which would lengthen the term of the permit by one year. In his evidence, Mr. V. L. Horte, Vice-President Gas Supply of Trans-Canada, said Trans-Canada's recent contracts run for a period of 25 years from the commencement of production and would, therefore, continue past October 31, 1990. Trans-Canada applied for the extension so that it would have, in effect, a 25-year permit from when the application was presented.

(2) Views of the Board

Terms of permits have been extended on other similar applications. The Board believes that where the applicant's qualifications would justify the granting to it of an original 25-year permit the extension applied for should be granted.

2. Additional Point of Interconnection and Measurement

(1) Views of Trans-Canada

The applicant asked that clauses 6 and 7 of the terms and conditions of the permit be amended so that it may receive gas from the facilities of The Alberta Gas Trunk Line Company

Limited, and cause the gas to be measured, at a point in the North-east quarter of Section 11, Township 38, Range 1, West of the 4th Meridian. This would be in addition to the present interconnection near Empress, about 108 miles to the south.

Trans-Canada stated that it has entered into a long-term contract to sell gas to Saskatchewan Power Corporation and to deliver the gas in the vicinity of the Unity storage field in Saskatchewan. For this purpose, Alberta Gas Trunk Line would construct a pipe line from its facilities in the Provost Field to the new proposed interconnection and Trans-Canada would construct a pipe line from that point to the Unity Field.

(2) Views of the Board

This proposed change will not, of itself, affect the aggregate volume of gas to be removed from the Province under the permit. The Board believes there is no reason why this amendment should not be granted.

3. Permit Year

(1) Views of Trans-Canada

In its application, Trans-Canada asked the Board to increase the daily, annual and total maximum volumes that could be removed under its permit. It expressed the annual maximum volume as being for "any consecutive twelve-month period". During the hearing the applicant expressed a preference for a fixed, rather than a rolling, twelve-month period, and with the leave of the Board, amended its application by adding, at the end of the above quoted phrase, the words "ending October

31". Mr. Horte said this would give Trans-Canada a greater degree of flexibility and that its heating season is from November 1 to October 31 and its contracts cover the same period.

(2) Views of the Board

Regulation of maximum annual volumes in accordance with a fixed year, as asked for by amendment to the application, will not affect the protection of the Alberta requirements and will simplify the surveillance of operations pursuant to the permit. The Board believes this amendment is desirable.

VI FINDINGS

The Board having heard publicly the application under The Gas Resources Preservation Act, 1956, of Trans-Canada Pipe Lines Limited, and having studied the evidence submitted by the applicant and the interveners at the public hearing, and having regard to the advice of its staff, to its own knowledge, and to its responsibility under the Act, finds as follows:

1. IN THE MATTER OF THE ESTABLISHED RESERVES OF GAS IN ALBERTA

The Board estimates the established reserves of marketable gas in the Province of Alberta, as of February 28, 1966, to be some 38.0 trillion cubic feet, or the equivalent of 40.3 trillion cubic feet of 1000 Btu gas.

Of the latter total some 3.1 trillion cubic feet of gas is now considered beyond economic reach and some 5.2 trillion cubic feet will have its production deferred, leaving a contractable reserve of 32.0 trillion cubic feet.

The current estimate is some 0.4 trillion cubic feet greater than the Board's estimate at December 31, 1965, and some 2.3 trillion cubic feet greater than its estimate at June 30, 1964.

Details of the Board's estimate are presented in Appendix A, and the significance of the contractable reserve is discussed in Section V.

2. IN THE MATTER OF THE TRENDS IN EXPLORATION AND THE GROWTH OF RESERVES OF GAS IN ALBERTA

Since 1951 the average growth in initial marketable reserves

of gas due to new discoveries and to appreciation of previous discoveries has been at the rate of some 2.5 trillion cubic feet per year. Over the past two years the actual annual rate was 3.1 trillion cubic feet.

The Board remains convinced that the Province may place full reliance upon additional reserves in the amount of 5.0 trillion cubic feet or equivalent to those that would be developed in a two-year period at the long term growth rate. In addition, it believes it would be justified in giving some further weight to future reserves under certain circumstances, as discussed in Section V.

Details of the Board's estimate of the growth of reserves in Alberta are presented in Appendix B.

3. IN THE MATTER OF THE PRESENT AND FUTURE REQUIREMENTS OF ALBERTA FOR GAS AND THE PRESENT PERMIT COMMITMENTS

The Board estimates the requirements of Alberta for 1000 Btu gas for the thirty-year period, January 1, 1966, to December 31, 1995, to be some 11.9 trillion cubic feet with a peak day requirement in the thirtieth year of about 2.6 billion cubic feet. The present estimate represents an increase of 1.6 trillion cubic feet in the total thirty-year requirements and 0.1 billion cubic feet in the thirtieth year peak day since the Board's last estimate in mid 1964.

The Board's present estimate of 11.9 trillion cubic feet includes a requirement of 1.0 trillion cubic feet for iron ore processing in the Peace River area and some 600 billion

cubic feet for the operation of The Alberta Gas Trunk Line Company Limited system, the Edmonton Liquid Gas plant, and the Empress plant.

Should Trans-Canada's present application be granted, the Trunk Line and Empress plant requirements together would increase by 110 billion cubic feet.

The remaining commitments as of February 28, 1966, associated with permits issued for the removal of gas from Alberta total some 19.4 trillion cubic feet of 1000 Btu gas.

A discussion of the submissions of interveners and the Board's study concerning the requirements of Alberta and details of the remaining permit commitments are presented in Appendix C.

4. IN THE MATTER OF THE METHOD USED TO CALCULATE THE GAS SURPLUS TO ALBERTA'S REQUIREMENTS

The Board finds considerable merit in the proposal advanced by Trans-Canada and by Alberta and Southern for determining the gas required to meet Alberta's thirty-year requirements and the gas surplus to these requirements. An attractive feature of the method is the division of the requirements, the reserves of gas needed to satisfy them and the resulting surpluses or deficiencies into contractable and future categories, thereby ensuring the availability of gas to meet Alberta's immediate as well as long term requirements. In view of this feature of the proposal and the fact that it was endorsed by interveners, the Board has reconsidered the

method it has used in the past, and has decided to adopt the principle of the method proposed.

A detailed discussion of the proposal, the Board's view regarding it, and the new method adopted by the Board is presented in Section V.

5. IN THE MATTER OF THE MEETING OF THE THIRTY-YEAR REQUIREMENTS OF ALBERTA AND THE PRESENT PERMIT COMMITMENTS, AND THE RESULTING SURPLUS

The Board estimates that reserves totalling some 18.0 trillion cubic feet of 1000 Btu gas are necessary to meet the annual and peak day requirements of Alberta for the thirty-year period January 1, 1966 to December 31, 1995. Of this total about 11.9 trillion cubic feet are required for actual deliveries with the remaining 6.1 trillion cubic feet being needed to meet the thirtieth year peak day.

The Board's estimate of 18.0 trillion cubic feet may also be considered to consist of 6.6 trillion cubic feet of contractable requirements and 11.4 trillion cubic feet of remaining requirements, the latter being a measure of the amount of reserves needed from sources not now under contract or connected to the Alberta market.

The Board estimates that 21.3 trillion cubic feet of 1000 Btu gas are required to meet the present permit commitments of which some 1.9 trillion cubic feet represent the reserves required to ensure deliverability in the terminal year for those permits under which it is contemplated that substantial

daily withdrawals for which protection has historically been provided will continue to the end of the term.

Deducting the contractable requirement of 6.6 trillion cubic feet and the gas needed to satisfy the permit commitment, 21.3 trillion cubic feet, from the contractable reserves of 32.0 trillion cubic feet leaves a contractable surplus of 4.1 trillion cubic feet.

The remaining and future reserves consist of 4.2 trillion cubic feet of deferred gas which will be available within the thirty-year period, 2.3 trillion cubic feet of gas now beyond economic reach but which is estimated will be within economic reach within thirty years, and 5.0 trillion cubic feet representing two years growth of gas reserves at the long term rate, giving a total of 11.5 trillion cubic feet. Comparing this total with the 11.4 trillion cubic feet of remaining Alberta requirements indicates a future surplus of 0.1 trillion cubic feet. This future surplus results after full provision for the 4.4 trillion cubic feet required from sources not now connected to meet the thirtieth year peak day and it is exclusive of the 1.9 trillion cubic feet required to protect the terminal year delivery of certain of the permits. Upon termination of the permits referred to 1.9 trillion cubic feet would become available to meet Alberta's requirements increasing the future surplus from 0.1 to 2.0 trillion cubic feet.

The overall surplus, consisting of the contractable surplus and the future surplus, is 4.2 trillion cubic feet

before the release of reserves required to protect the terminal year deliveries of certain of the permits and 6.1 trillion cubic feet after the release of this cushion gas.

Since the future reserves exceed the remaining requirements of Alberta, the new method gives an overall surplus which is identical to the surplus determined by the method formerly used by the Board.

Details of the Board's analyses of these matters appear in Appendix D.

6. IN THE MATTER OF THE VOLUMES UNDER CONTRACT AND THE PERMIT VOLUME REQUESTED BY TRANS-CANADA PIPE LINES LIMITED

The Board finds that Trans-Canada has under contract over 95 per cent of the reserves, as estimated by the Board to be within the fields, pools, and areas which the applicant requested be added to its permit. Furthermore, with the exception of two small areas where reserves totalling some 6 billion cubic feet are not under contract to the applicant, and which the Board believes should not be included in the permit, Trans-Canada has under contract a substantial portion of the reserves in each field, pool or area it wishes added to its permit.

7. IN THE MATTER OF THE APPLICANT'S REQUEST FOR AUTHORIZATION FOR THE REMOVAL OF ADDITIONAL QUANTITIES OF GAS AND THE SURPLUS WHICH WOULD RESULT IF THE REQUEST IS GRANTED

Trans-Canada requested authority to remove an additional 2.92 trillion cubic feet of gas, consisting of approximately

0.3 trillion cubic feet from fields included in its present permit and some 2.6 trillion cubic feet from new fields. While the Board disagrees with the applicant's estimate of reserves in certain of the new fields and in some of the fields now in the permit, the Board's estimate of the total reserves available in both groups of fields is slightly in excess of the amount requested by the applicant.

The Board finds that the additional volume of gas requested by the applicant is surplus to the present and future annual and peak day requirements of the Province and may be produced within the requested term - although the reserves would not support full deliverability for the last several years of the term.

If the increased volume requested be approved, the reserves needed to meet the commitment of all permits would increase from the present 21.3 trillion cubic feet of 1000 Btu gas, of which 1.9 trillion cubic feet is for the protection of deliveries at the maximum days authorized and anticipated in the permits, to 24.3 trillion cubic feet, including the 1.9 trillion cubic feet peak day protection for the other permits.

The increased requirements of Alberta and the additional volume requested would reduce the contractable surplus from 4.1 to 1.1 trillion cubic feet, the future surplus from 0.1 trillion cubic feet to nil and the overall surplus from 4.2 to 1.1 trillion cubic feet. Both the future surplus and the overall surplus would be increased by the 1.9 trillion cubic

feet after the expiry of other permits.

Details of the Board's analyses relating to these matters are presented in Appendix E.

8. IN THE MATTER OF THE OTHER AMENDMENTS REQUESTED BY TRANS-CANADA PIPE LINES LIMITED

(1) The request for an extension in the term of its present permit.

The Board agrees with the applicant that the addition to reserves, the delivery characteristics of the fields, and the contracts which Trans-Canada has entered into make an extension of the term of the present permit desirable.

(2) The request that an additional point of interconnection and measurement be included in the present permit.

The inclusion in the permit of an additional point at which gas will be received and measured before removal from the Province will not, of itself, affect the aggregate volume of gas to be removed under the permit. The Board, therefore, believes there is no reason why this amendment should not be granted.

(3) The request that the annual volume of gas that could be removed be on the basis of a fixed year.

Trans-Canada asked that the annual volume of gas that could be removed from Alberta under the terms of the amended permit be expressed as being for a fixed twelve-month period ending October 31, rather than a "rolling" twelve-month period.

The Board believes this amendment is desirable since the applicant's heating season and its contracts are from November 1, to October 31, and it will give Trans-Canada a degree of flexibility. Furthermore, it will make the Board's surveillance of operations pursuant to the permit easier.

9. IN THE MATTER OF THE DISPOSITION OF THE APPLICATION OF TRANS-CANADA PIPE LINES LIMITED

All things considered, the Board is prepared, with the approval of the Lieutenant Governor in Council, to amend Permit No. TC 64-6 by increasing the volume of gas which Trans-Canada Pipe Lines Limited may remove from the Province by 2.92 trillion cubic feet, by adding to the list of fields, pools and areas from which the gas may be removed, and by making the other amendments applied for by the applicant; the amendment of permit to be in the form shown in Appendix F and subject to the terms and conditions therein contained.

Respectfully submitted,

G. W. Govier, P. Eng.
Chairman

A. F. Manyluk, P.Eng.
Deputy Chairman

Vernon Millard
Board Member

Dated at Calgary, Alberta
this 23rd day of June, 1966.

APPENDIX A

THE ESTABLISHED RESERVES OF GAS IN ALBERTA

The Board estimates that the initial marketable reserves of gas in Alberta have increased from some 43.0 trillion cubic feet as of December 31, 1965, to some 43.5 trillion cubic feet as of February 28, 1966, - an increase of 0.5 trillion cubic feet during the two-month period, with all volumes based on the actual Btu content.

To February 28, 1966, a total of some 5.5 trillion cubic feet of marketable gas have been produced, 0.1 trillion of which were produced during the first two months of 1966.

The remaining marketable gas at February 28, 1966, is estimated to be 38.0 trillion cubic feet (equivalent to 40.3 trillion cubic feet of 1000 Btu gas), an increase of some 0.4 trillion cubic feet since December 31, 1965. The Board considers that of the total of 38.0 trillion cubic feet, some 35.1 trillion cubic feet are presently within economic reach, 5.0 trillion cubic feet constitute deferred reserves, and 2.9 trillion cubic feet are presently beyond economic reach. In comparison the Alberta Division of Canadian Petroleum Association submitted that there were some 38 trillion cubic feet of marketable gas reserves in Alberta as of December 31, 1965. It did not submit an estimate for February 28, 1966.

The major portion of the increase in remaining marketable reserves since December 31, 1965, is due to the re-evaluation of certain geological and engineering factors employed in the

calculation of the initial marketable reserves in various areas and the development of previous discoveries. There were no new discoveries of significance during the two-month period ending February 28, 1966.

The Board, in its estimate of reserves, has considered evidence presented at the hearing by Trans-Canada, evidence presented by the various operators at the hearing and at other times during the previous years, and evaluations completed by its staff.

The Board's estimate of the growth in reserves in the fields from which the applicant is now removing, or expects to be removing gas, plus the reserves in fields or areas from which it proposes to remove gas slightly exceeds the volume requested for removal from the Province. While there is general agreement between the Board and the applicant in the overall estimate of reserves, there are differences in the estimates for some of the individual fields. Furthermore, operators active in certain of the fields and areas presented detailed estimates of reserves which in most cases exceeded those of the applicant and of the Board. The more significant differences and the reasons for variation are presented in the following tabulation:

Field or Area	Zone	Estimator	Initial Established Reserves Bcf	Remarks
Brazeau River	Mississippian	Trans-Canada	613	Trans-Canada had much larger areal extent - especially in the "probable" category.
		Board	320	

Field or Area	Zone	Estimator	Initial Established Reserves Bcf	Remarks
Craigend	Grosmont	Trans-Canada Supertest Board	133 236 170	Drilling subsequently to the Trans-Canada estimate, but prior to February 28, 1966, and the Supertest estimate estended the areal extent of the pool. The Board has considered this drilling but assigned a lesser areal extent than did Supertest.
Edson	Mississippian	Trans-Canada Board	2010 1700	Board reserve based on two pool concept. Trans-Canada reserve based on one continuous pool and thus a larger area.
Ghost Pine	All Zones	Trans-Canada Board	405 129	Board had much less areal extent. Interwell correlation differences often resulted in isopachs for Trans-Canada but acreage assignments or smaller isopachs for the Board.
Gold Creek	Wabamun	Trans-Canada Pan American Board	687 760 500	Trans-Canada and Pan American had larger areal extent-especially in the "probable" category.
Marten Hills	Wabamun	Trans-Canada Pan American Board	235 534 236	Board and Trans-Canada in close agreement. Pan American had much larger areal extent.
Marten Hills	Wabiskaw	Trans-Canada Pan American Board	468 622 450	Board and Trans-Canada in close agreement. Pan American had much larger areal extent.

Field or Area	Zone	Estimator	Initial Established Reserves Bcf	Remarks
Olds	Wabamun	Trans-Canada	431	Board had much less areal extent due to different interpretation of potential well deliverability in certain areas.
		Board	250	
Provost	Viking	Trans-Canada	880	Board had less areal extent and less pay for most wells.
		Board	620	

During the period January 1 to February 28, 1966, in the Province as a whole, there have been some changes in the estimate of initial marketable reserves in certain of the previously known pools. Four of the pools where significant changes were recorded are listed and discussed briefly in the following paragraphs.

Brazeau River Mississippian. Additional geological information from two new wells drilled during the two-month period under consideration has resulted in an increased estimate of the areal extent of the pool. As a result the initial marketable reserve was increased from 300 billion cubic feet to 320 billion cubic feet as of February 28, 1966.

Crossfield Wabamun. The drilling of two new wells, plus new information on two former suspensions has increased the proven areal extent of this reserve. For the period ending February 28, 1966, the Board has estimated the initial marketable reserve to be 740 billion cubic feet, which represents an appreciation of 60 billion cubic feet over the two-month period since December 31, 1965.

Crossfield East Wabamun. Two new wells have been drilled and isopached with two wells formerly in the Olds area, and one well formerly in the Lone Pine Creek area. As a result the initial marketable reserve for this area has increased from 370 billion cubic feet at December 31, 1965, to 510 billion cubic feet at February 28, 1966.

Nevis Devonian. Two new wells plus geological re-interpretation has accounted for the increase of 30 billion cubic feet in initial marketable reserves since December 31, 1965. As of February 28, 1966, the initial marketable reserve for this zone was estimated at 700 billion cubic feet.

The Board's estimates of established reserves are presented in Table A-1. The table does not show individually fields or areas having a marketable reserve of less than 10 billion cubic feet unless the reserve is supplying a market. In addition, the table does not show individually fields or areas in which the data used in calculating the reserve is confidential. However, the sum of the reserves for non-producing fields or areas having a reserve of less than 10 billion cubic feet and the sum of the reserves for confidential fields or areas are shown at the end of the table, and are included in the Provincial total. The fields and areas contained in Table A-1 are illustrated in Figure A-1.

TABLE A - 1

OIL AND GAS CONSERVATION BOARD

ESTABLISHED RESERVES OF GAS IN THE PROVINCE OF ALBERTA, FEBRUARY 28, 1966

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO FEB. 28, 1966 BCF	(7) REMAINING MARKETABLE GAS FEB. 28, 1966 BCF	(8) ESTIMATED HEATING VALUE BTU/CU.FT.	(9) REMAINING MARKETABLE GAS (1000 BTU BASIS) BCF	(10) REMARKS
Acheson	Viking	6	25/5	4	1	3	1020*	3	Gas sold to Northwestern
	Basal Blairmore	37	20/15	25	3	22	1020	22	Utilities, Limited
	Leduc Solution	68	35/55	20	5	15	1140	17	
Acheson East	Basal Blairmore	12	15/5	10	--	10	1090	11	Presently considered beyond Economic reach
Aden	Bow Island	5	20/5	4	--	4	1000	4	
	Basal Colorado	6	15/5	5	1	4	1000	4	Gas sold to Canadian-Montana
	Sunburst-Swift	3	20/5	2	1	1	1040	1	Gas Company Ltd.
	Mississippian	12	10/10	10	4	6	1040	6	
Alderson	Milk River	32	25/5	23	5	18	960	17	Supplies local utility
	Second White Specks	280	25/5	202	--	202	995	202	Includes area formerly known
	Bow Island	8	25/5	6	--	6	1000	6	as Monogram South
Alexander	Basal Blairmore	130	10/5	110	99	11	1060*	12	Gas sold to North Canadian Oils Limited and Calgary Power Ltd.
Alix	Basal Blairmore	12	10/5	10	--	10	1090	11	Presently considered beyond Economic reach
	Nisku Assoc. and Non-Assoc.	9	15/10	7	--	7	1130	8	
Antelope	Viking	20	20/5	15	1	14	1020	14	Gas sold to Trans-Canada
	Banff	12	20/5	9	2	7	1020	7	Pipe Lines Limited
Athabasca	Grand Rapids	6	15/5	5	1	4	1000*	4	Supplies local utility
	Wabamun	4	10/5	3	--	3	980*	3	
Athabasca East	Wabamun	2	10/5	2	1	1	1000	1	Supplies local utility
Atlee Buffalo	Bow Island	120	25/5	85	9	76	970*	74	Gas sold to Trans-Canada
	Basal Colorado	7	15/5	6	--	6	1020	6	Pipe Lines Limited
	Basal Blairmore	72	20/5	55	--	55	960*	53	

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO FEB. 28, 1966 BCF	(7) REMAINING MARKETABLE GAS FEB. 28, 1966 BCF	(8) ESTIMATED HEATING VALUE BTU/CU.FT.	(9) REMAINING MARKETABLE GAS (1000 BTU BASIS) BCF	(10) REMARKS
Bantry	Milk River	46	20/5	35	1	34	960	33	Supplies local utility
	Basal Colorado	3	20/5	2	--	2	970	2	
	Bow Island	26	20/5	20	--	20	970	19	
	Mannville	37	15/5	30	2	28	1030	29	
	Mannville Assoc.	37	15/5	30	--	30	1160	35	
Baptiste	Mannville	1	20/5	1	--	1	970	1	Formerly known as Athabasca North Area
	Wabamun	14	20/5	11	--	11	980	11	
Bashaw	Viking	1	25/5	1	--	1	970	1	
	Basal Blairmore	25	15/5	20	--	20	970	19	
	Leduc Assoc.	18	20/15	12	1	11	1220	13	
Bawlf	Viking	21	25/5	15	--	15	1020	15	Presently considered beyond economic reach
	Blairmore	5	30/5	3	--	3	1050	3	
Beaverhill Lake-Fort Saskatchewan	Viking	620	15/5	500	90	410	1020*	420	Gas sold to Northwestern Utilities, Limited and Canadian Industrial Gas & Oil Ltd.
	Blairmore	4	15/5	3	--	3	1000	3	
Bellis	Mannville	5	20/5	4	--	4	1000	4	
	Nisku	45	15/5	36	--	36	1000	36	
Belloy	Notikewin	9	20/5	7	--	7	1000	7	Presently considered beyond economic reach
	Gething	62	15/5	50	--	50	1000	50	
	Mississippian	23	10/5	20	--	20	1120	22	
Bellshill Lake	Viking	6	25/5	4	--	4	1040	4	Presently considered beyond economic reach
	Blairmore	37	15/5	30	--	30	990	30	
	Blairmore Assoc.	3	15/10	2	--	2	990	2	
Benjamin Creek	Mississippian	100	15/20	70	--	70	1070	75	
Berland River	Leduc	440	10/25	300	--	300	1000	300	
Berland River West	Wabamun	24	10/30	15	--	15	1020	15	Presently considered beyond Economic reach
Bigoray	Blairmore	14	15/5	11	--	11	1080	12	
	Mississippian	13	15/10	10	--	10	1080	11	
Bigstone	Gething	23	10/5	20	--	20	1100	22	
	Dunvegan	29	10/5	25	--	25	1140	28	
	Wabamun	10	15/40	5	--	5	1050	5	
	Leduc	390	15/25	250	--	250	930	230	

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BINDLOSS	VIKING	430	15/5	350	75	275	980*	270	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED
	BASAL BLAIRMORE	31	15/5	25		25	990	25	
BITTERN LAKE	VIKING	3	25/5	2	--	2	1020	2	
	BLAIRMORE	53	15/5	43	--	43	1070	46	
BLACK BUTTE	BOW ISLAND	21	15/5	17	2	15	1010	15	GAS SOLD TO CANADIAN-MONTANA GAS COMPANY LTD.
	BASAL COLORADO	25	15/5	20	6	14	1000	14	
	BLAIRMORE	6	15/5	5	--	5	1000	5	
	SUNBURST-ELLIS	35	10/5	30	21	9	1000	9	
	MISSISSIPPIAN	11	15/5	9	3	6	1020	6	
BLUERIDGE	DETRITAL	14	10/5	12	--	12	1100	13	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
	MISSISSIPPIAN	1	20/5	1	--	1	1130	1	
BOLLOQUE LAKE	VIKING	3	25/5	2	--	2	1040	2	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
	BASAL BLAIRMORE	11	25/5	8	--	8	1100	9	
BONNIE GLEN	CARDIUM SOLUTION	1	15/10	1	--	1	1040	1	
	VIKING	3	15/10	2	--	2	1050	2	
	BLAIRMORE	5	15/10	4	3	1	1100	1	GAS SOLD TO NORTHWESTERN UTILITIES, LIMITED
	LEDUC ASSOC.	430	10/15	330	6	324	1220	395	
	LEDUC SOLUTION	530	35/25	260	39	221	1220	270	
BONNYVILLE	BLAIRMORE	5	20/5	4	2	2	980	2	SUPPLIES LOCAL UTILITY
BOUNDARY LAKE SOUTH	CADOMIN	10	15/5	8	--	8	1060	8	
	BOUNDARY LAKE	1	15/10	1	--	1	1050	1	
	MISSISSIPPIAN	58	15/5	47	14	33	1040*	34	GAS SOLD TO WESTCOAST TRANSMISSION COMPANY LIMITED
BOW ISLAND	BOW ISLAND	20	20/5	15	-4	19	1110	21	CANADIAN WESTERN NATURAL GAS COMPANY LIMITED STORAGE RESERVOIR
BOYLE	BLAIRMORE	3	20/5	2	--	2	1000	2	
	DETRITAL	1	15/5	1	--	1	1000	1	
	NISKU	10	15/5	8	--	8	990	8	

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Braeburn	Cadomin	4	15/5	3	--	3	1060	3	
	Triassic	33	15/10	25	2	23	1090	25	Gas sold to Westcoast
	Permo-Penn	52	15/10	40	2	38	1030	39	Transmission Company Limited
Brazeau River	Mississippian	420	15/10	320	--	320	1040	333	
Brooks	Milk River	9	20/5	7	3	4	990	4	Supplies local utility
Brown Creek	Mississippian	59	20/15	40	--	40	970	39	Presently considered beyond economic reach
Bruce	Viking	13	25/5	9	--	9	1000	9	
	Mannville	10	20/10	7	--	7	1020	7	
Burnt Timber	Mississippian	390	20/20	250	--	250	1080	270	
Calling Lake	Mannville	3	25/5	2	--	2	1000	270	
	Nisku	49	25/5	35	--	35	1000	35	
Campbell-Namao	Blairmore Non Assoc., Assoc. & Solution	38	20/5	29	12	17	1020	17	Gas sold to Canadian Industrial Gas & Oil Ltd.
Carbon	Viking	5	20/5	4	--	4	1020	4	
	Basal Colorado	4	15/5	3	--	3	1020	3	
	Blairmore	150	15/5	122	11	111	1100	122	Gas sold to Canadian Western Natural Gas Company Limited
Caroline	Viking	135	20/10	97	--	97	1130	110	Formerly included in
	Blairmore	39	15/10	30	--	30	1070	32	Garrington Area
	Mississippian	25	15/10	19	--	19	1020	19	
Carson Creek	Beaverhill Lake	320	15/15	230	-3	233	1050	245	Reservoir being cycled
Carson Creek North	Beaverhill Lake Assoc.	28	15/15	20	--	20	1100	22	
	Beaverhill Lake Solution	440	60/20	140	3	137	1100	151	Gas injected into Carson Creek
Carstairs	Basal Blairmore	5	15/10	4	--	4	1100	4	Gas sold to Trans-Canada Pipe
	Mississippian	1100	15/10	860	164	696	1110*	772	Lines Limited

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CASTOR	VIKING	5	20/5	4	--	4	1090*	4	SUPPLIES LOCAL UTILITY
	BLAIRMORE	2	10/5	2	--	2	1090*	2	
CESSFORD	VIKING	110	15/5	90	6	84	1020*	86	GAS SOLD TO TRANS-CANADA
	BASAL COLORADO	1200	15/5	1000	264	736	1020	751	PIPE LINES LIMITED
	BASAL BLAIRMORE	460	15/5	370	62	308	1030*	318	
CHIGWELL	BLAIRMORE	74	10/10	60	8	52	1100*	57	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED
CHINOOK RIDGE	PADDY	12	10/10	10	--	10	1020	10	PRESENTLY CONSIDERED
	CADOTTE	31	10/10	25	--	25	1020	25	BEYOND ECONOMIC
	NOTIKEWIN	19	10/10	15	--	15	1020	15	REACH
CHISHOLM	BLAIRMORE	12	10/5	10	--	10	1020	10	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
CLEAR HILLS	GETHING	1	15/5	1	--	1	980	1	PRESENTLY CONSIDERED
	TRIASSIC	8	10/5	7	--	7	1030	7	BEYOND ECONOMIC REACH
	LEDUC	4	15/5	3	--	3	1070	3	
CLIVE	VIKING	4	20/5	3	--	3	990	3	PRESENTLY CONSIDERED
	BLAIRMORE	6	15/5	5	--	5	1020	5	BEYOND ECONOMIC REACH
	NISKU ASSOC.	14	10/15	11	--	11	1150	13	
	LEDUC ASSOC.	13	10/25	9	--	9	1200	11	
COLD LAKE	BLAIRMORE	6	25/5	4	3	1	1000	1	SUPPLIES LOCAL UTILITY
COMREY	SECOND WHITE SPECKS	4	20/5	3	--	3	940	3	GAS SOLD TO CANADIAN-
	BOW ISLAND	29	10/5	25	14	11	940	10	MONTANA GAS COMPANY LTD.
CONNORSVILLE	VIKING	8	20/5	6	1	5	990	5	GAS SOLD TO TRANS-CANADA
	BASAL BLAIRMORE	62	15/5	50	1	49	1130	55	PIPE LINES LIMITED
COUNTESS	BOW ISLAND	92	20/5	70	4	66	1000*	66	GAS SOLD TO TRANS-CANADA
	BASAL COLORADO	140	25/5	100	49	51	1000*	51	PIPE LINES LIMITED
	BASAL BLAIRMORE	43	20/5	33	3	30	1020*	31	
	MISSISSIPPIAN	2	15/5	2	-	2	960	2	
	MISSISSIPPIAN ASSOC.	3	20/10	2	-	2	960	2	

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CRAIGEND	GRAND RAPIDS	11	25/5	8	--	8	1000	8	
	GROSMONT	240	25/5	170	--	170	1000	170	
CRIMSON LAKE	CARDIUM	22	20/10	16	--	16	1100	18	
CROSSFIELD	BASAL BLAIRMORE	100	15/10	80	--	80	1100	88	GAS SOLD TO ALBERTA AND
	CALGARY ELKTON	900	15/15	650	114	536	1120*	600	SOUTHERN GAS CO. LTD. AND
	CROSSFIELD ELKTON	1200	10/10	1000	86	914	1120*	1020	WESTCOAST TRANSMISSION COMPANY
	WABAMUN	1700	15/50	740	41	699	1120*	782	LIMITED
CROSSFIELD EAST	BLAIRMORE	1	15/10	1	--	1	1000	1	
	MISSISSIPPIAN	130	10/15	100	10	90	1120	101	GAS SOLD TO TRANS-CANADA
	WABAMUN	1400	10/60	510	--	510	1060	540	PIPE LINES LIMITED
DIXONVILLE	GETHING	12	10/5	10	--	10	1000	10	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
DONALDA	VIKING	40	20/5	30	--	30	970	29	PRESENTLY CONSIDERED BEYOND
	BASAL BLAIRMORE	5	15/5	4	--	4	970	4	ECONOMIC REACH
	DETRITAL	5	20/5	4	--	4	990	4	
DOWLING LAKE	BASAL BLAIRMORE	5	20/5	4	1	3	1030*	3	SUPPLIES LOCAL UTILITY
DRUMHELLER	VIKING	3	25/5	2	--	2	1080	2	
	BLAIRMORE	48	10/5	41	--	41	1080	44	
	MISSISSIPPIAN	2	10/10	2	--	2	1080	2	FORMERLY INCLUDED IN ROWLEY AREA
DUHAMEL	VIKING	4	10/5	3	--	3	1000	3	PRESENTLY CONSIDERED BEYOND
	BLAIRMORE	4	10/5	3	--	3	1030	3	ECONOMIC REACH
	DEVONIAN	14	40/15	7	--	7	1100	8	
DUVERNAY	VIKING	4	20/5	3	2	1	1000*	1	GAS SOLD TO WESTERN MINERALS LTD. PLANT AND SUPPLIES LOCAL UTILITY
DYBERG	BELLY RIVER	2	20/5	2	--	2	950	2	PRESENTLY CONSIDERED
	VIKING	8	10/5	7	--	7	1000	7	BEYOND ECONOMIC REACH
	BASAL BLAIRMORE	12	10/5	10	--	10	1020	10	

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EAGLESHAM	GETHING	6	15/5	5	--	5	1000	5	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
	CADOMIN	6	15/5	5	--	5	1060	5	
	MISSISSIPPIAN	62	15/5	50	--	50	1110	56	
EDSON	GETHING	92	15/10	70	--	70	1050	74	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED
	MISSISSIPPIAN	2400	15/15	1700	11	1689	1030	1740	
EDWAND	MANNVILLE	9	20/5	7	--	7	1000	7	SUPPLIES LOCAL UTILITY
ELK POINT	MANNVILLE	3	20/5	2	1	1	990*	1	SUPPLIES LOCAL UTILITY
ELLERSLIE	BLAIRMORE	3	20/5	2	1	1	1000	1	GAS SOLD TO EDMONTON LIQUID GAS LTD,
ENCHANT	MILK RIVER	5	30/5	3	--	3	1030	3	
	BOW ISLAND	25	25/5	18	2	16	960*	15	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED
	BASAL BLAIRMORE	12	15/10	10	2	8	1040*	8	
	ELLIS	3	25/10	2	--	2	1030	2	
	MISSISSIPPIAN	5	15/10	4	1	3	1040*	3	
EQUITY	MANNVILLE	4	20/5	3	--	3	1000	3	
	MISSISSIPPIAN	30	15/10	20	--	20	1100	22	
ERSKINE	VIKING	4	20/5	3	--	3	1040	3	
	BLAIRMORE	24	20/10	17	1	16	1090	17	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED
	LEDUC ASSOC.	29	10/20	21	--	21	1070	22	
	LEDUC SOLUTION	18	35/75	3	--	3	1110	3	
ESTHER	VICTORIA	23	30/5	15	--	15	990	15	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED
	BANFF	20	10/5	17	--	17	1000	17	
ETZIKOM	BOW ISLAND	79	20/5	60	29	31	930	29	GAS SOLD TO SOUTH ALBERTA PIPE LINES LTD.
	BASAL BLAIRMORE	1	25/5	1	--	1	1010	1	
EXCELSIOR	VIKING	9	15/5	7	2	5	1000	5	GAS SOLD TO CANADIAN INDUSTRIAL GAS LIMITED AND PLAINS-WESTERN GAS LTD.
	BASAL BLAIRMORE	39	10/5	33	--	33	970	32	
EYREMORE	BOW ISLAND	15	30/5	10	--	10	960	10	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
FAIRYDELL-BON ACCORD	VIKING	130	20/5	100	14	86	1020*	88	GAS SOLD TO NORTHWESTERN UTILITIES, LIMITED
	BASAL BLAIRMORE	20	20/5	15	2	13	990*	13	

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Faust South	Gething	12	10/5	10	--	10	990	10	Presently considered beyond economic reach
Fenn-Big Valley	Viking	20	20/5	15	5	10	1000*	10	Gas sold to Northwestern Utilities, Limited
	Nisku Solution	150	45/35	53	7	46	1110	51	
	Leduc Assoc. and Solution	13	45/45	4	1	3	1110	3	
Ferrier	Cardium	8	20/10	6	--	6	1000	6	
	Nordegg	4	25/5	3	--	3	1080	3	
	Mississippian	3	20/10	2	--	2	1100	2	
Figure Lake	Viking	4	25/5	3	--	3	960	3	
	Blairmore	13	20/5	10	--	10	1000	10	
	Nisku	25	15/5	20	--	20	1000	20	
Flatbush	Mannville	13	20/5	10	--	10	1000	10	Presently considered beyond economic reach
Foremost	Bow Island	33	15/5	27	6	21	950	20	Gas sold to Canadian Western Natural Gas Company Limited
Fort Kent	Blairmore	5	20/5	4	1	3	980	3	Supplies Local Utility
Fox Creek	Viking	6	15/5	5	--	5	1160	6	
	Gething	1	25/5	1	--	1	1160	1	
	Triassic	5	15/10	4	--	4	1160	5	
Fox Creek North	Viking	33	20/5	25	--	25	1160	29	
	Cadomin	17	20/5	13	--	13	1160	15	
Fox Creek West	Viking	4	25/5	3	--	3	1160	3	
	Gething	15	10/5	13	--	13	1020	13	
	Nisku	18	10/20	13	--	13	1150	15	
Garrington	Viking Assoc. and Non-Assoc.	4	20/10	3	--	3	1130	3	
	Blairmore	12	15/10	9	--	9	1010	9	
	Mississippian	1	15/10	1	--	1	1020	1	
	Leduc	46	15/20	31	--	31	1020	32	

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GHOST PINE	VIKING	9	20/5	7	--	7	1020	7	
	BLAIRMORE	94	15/10	72	--	72	1030	74	
	BLAIRMORE ASSOC.	16	20/5	12	--	12	1050	13	
	MISSISSIPPIAN	47	15/5	38	--	38	1070	41	
GILBY	CARDIUM	3	15/10	2	--	2	1000	2	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED
	VIKING ASSOC AND NON-ASSOC.	4	20/5	3	--	3	1220	4	
	VIKING SOLUTION	17	40/40	6	--	6	1250	8	
	BLAIRMORE	290	10/15	220	7	213	1090*	232	
	BLAIRMORE SOLUTION	20	40/40	7	--	7	1250	9	
	JURASSIC ASSOC. AND NON ASSOC.	250	20/10	180	11	169	1090*	184	
	JURASSIC SOLUTION	43	50/40	13	-	13	1100	14	
	PEKISKO	420	10/15	320	58	262	1090*	286	
	BANFF ASSOCIATED	4	20/15	3	--	3	1100	3	
	WABAMUN	7	10/20	5	--	5	1170	6	
GLENEVIS	MANNVILLE	15	15/5	12	--	12	1040	12	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
GLEN PARK	BASAL BLAIRMORE	7	20/5	5	1	4	1140	5	GAS SOLD TO NORTHWESTERN UTILITIES, LIMITED
	LEDUC SOLUTION	16	35/15	9	1	8	1250	10	
GOLD CREEK	WABAMUN	840	15/30	500	--	500	1050	525	
GOLDEN SPIKE	VIKING	8	20/5	6	1	5	1050	5	GAS INJECTED INTO LEDUC ZONE
	BLAIRMORE	22	10/5	19	1	18	1050	19	
	WABAMUN	26	10/15	20	10	10	1060	11	
	NISKU ASSOC.	4	15/15	3	--	3	1220	4	
	NISKU SOLUTION	6	35/20	3	1	2	1220	2	
	LEDUC SOLUTION	130	30/30	64	-22	86	1290	111	
GOODWIN LAKE	JURASSIC	20	15/10	15	--	15	1070	16	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
GORDONDALE	PADDY	84	65/5	28	22	6	1000	6	GAS SOLD TO WESTCOAST TRANSMISSION COMPANY LIMITED
	GETHING	60	25/5	43	28	15	1020	15	
GREENCOURT	JURASSIC-DETRITAL	65	15/10	50	--	50	1070	54	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
	MISSISSIPPIAN ASSOC.	37	25/10	25	--	25	1130	28	

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO FEB. 28, 1966 BCF	(7) REMAINING MARKETABLE GAS FEB. 28, 1966 BCF	(8) ESTIMATED HEATING VALUE BTU/CU.FT.	(9) REMAINING MARKETABLE GAS (1000 BTU BASIS) BCF	(10) REMARKS
HACKETT	BASAL BLAIRMORE	62	10/10	50	3	47	1100	52	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED
HAIRY HILL	VIKING	1	25/5	1	--	1	980	1	
	BLAIRMORE	23	10/5	20	8	12	1000*	12	GAS SOLD TO WESTERN MINERALS LTD.
	NISKU	3	20/5	2	--	2	1000	2	
HAMELIN CREEK	CADOTTE	3	20/5	2	--	2	1000	2	
	GETHING	4	15/5	3	--	3	1010	3	
	CADOMIN	21	15/5	17	5	12	1060	13	SUPPLIES LOCAL UTILITY
HAMILTON LAKE	VIKING ASSOCIATED AND NON ASSOCIATED	13	25/5	9	--	9	1040	9	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
	UPPER MANNVILLE	5	15/5	4	--	4	1050	4	
HARMATTAN EAST	MISSISSIPPIAN ASSOCIATED	1200	10/15	900	-7	907	1080	980	RESERVOIR BEING CYCLED
	MISSISSIPPIAN SOLUTION	170	25/25	97	7	90	1280	115	GAS INJECTED INTO GAS CAP
HARMATTAN-ELKTON	MISSIPPIAN	55	15/15	40	1	39	1040	41	
	MISSISSIPPIAN ASSOCIATED	1200	10/15	900	-21	921	1080	995	RESERVOIR BEING CYCLED
	MISSISSIPPIAN SOLUTION	180	25/30	96	21	75	1280	96	GAS INJECTED INTO GAS CAP
	LEDUC	500	15/60	170	--	170	1100	187	
HEART RIVER	CADOTTE	2	15/5	2	--	2	1000	2	SUPPLIES LOCAL UTILITY
	NOTIKEWIN	2	10/5	2	--	2	1000	2	
HERCULES	VIKING	19	15/5	15	--	15	1050	16	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
	BLAIRMORE	29	10/5	25	--	25	960	24	
HIGH PRAIRIE	CADOTTE	4	15/5	3	--	3	1000	3	
	NOTIKEWIN	7	15/5	6	--	6	1100	7	
	GETHING	1	15/5	1	--	1	1000	1	
HOLBURN	CARDIUM	6	25/5	4	--	4	980	4	
	BLAIRMORE	25	20/10	18	--	18	1120	20	
HOLMBERG	BLAIRMORE	25	15/5	20	-	20	1050	21	GAS SOLD TO BAROID OF CANADA, LTD. PLANT

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO FEB. 28, 1966 BCF	(7) REMAINING MARKETABLE GAS FEB. 28, 1966 BCF	(8) ESTIMATED HEATING VALUE BTU/CU.FT.	(9) REMAINING MARKETABLE GAS (1000 BTU BASIS) BCF	(10) REMARKS
Homeglen-Rimbey	Leduc Associated and Solution	1000	10/15	800	161	639	1070*	684	Gas sold to Trans-Canada Pipe Lines Limited and Alberta and Southern Gas Co. Ltd.
Hunter Valley	Mississippian	78	15/25	50	--	50	1080	54	
Hussar	Belly River	3	25/5	2	1	1	1000	1	Gas sold to Trans-Canada Pipe Lines Limited
	Viking	68	20/5	52	5	47	1020*	48	
	Basal Colorado	56	25/5	40	10	30	1020*	31	
	Blairmore	620	15/5	502	81	421	1050*	442	
Inland	Viking	21	25/5	15	--	15	980	15	
Innisfail	Mississippian	22	10/10	18	--	18	1080	19	
	Wabamun	4	15/15	3	--	3	1170	4	
	Leduc Assoc.	17	10/35	10	--	10	1020	10	
	Leduc Solution	200	45/45	60	13	47	1130*	53	Gas sold to Trans-Canada Pipe Lines Limited
Jarrow	Viking	4	25/5	3	--	3	1010	3	
	Mannville	10	15/5	8	--	8	1030	8	
Jarvie	Viking	10	25/5	7	--	7	1040	7	Presently considered beyond economic reach
	Blairmore	10	15/5	8	--	8	1100	9	
Jenner	Bow Island	4	25/5	3	--	3	990	3	
	Basal Colorado	7	20/5	5	--	5	1040	5	
	Blairmore	29	20/5	22	--	22	1050	23	
	Mississippian	2	15/5	2	--	2	1000	2	
Joarcam	Viking Assoc.	66	20/5	50	--	50	1040	52	To be used for Pressure Maintenance
Joffre	Viking	1	25/5	1	--	1	1000	1	Presently considered beyond economic reach
	Basal Blairmore	44	20/10	32	--	32	1020	33	
	Leduc	3	15/10	2	--	2	1050	2	
Judy Creek	Viking	13	20/5	10	--	10	1020	10	Gas sold to Northwestern Utilities, Limited
	Beaverhill Lake Solution	820	55/35	240	9	231	1080	249	
Judy Creek South	Mississippian	12	10/10	10	--	10	1050	11	Presently considered beyond economic reach

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Jumping Pound	Mississippian	760	15/15	550	227	323	1050	339	Gas sold to Canadian Western Natural Gas Company Limited
Jumping Pound West	Mississippian	1100	20/20	700	--	700	1050	735	
Kaybob	Notikewin	310	15/5	250	37	213	1100*	234	Gas sold to Alberta and Southern Gas Co. Ltd.
	Spirit River	7	15/5	6	--	6	1000	6	
	Gething	15	15/5	12	--	12	1050	13	
	Cadomin	120	15/5	100	--	100	1040	104	
	Winterburn	5	15/35	3	--	3	1070	3	
	Beaverhill Lake Assoc.	4	20/15	3	--	3	1070	3	
	Beaverhill Lake Solution	330	60/25	100	5	95	1140	108	
Kaybob South	Viking	26	20/5	20	--	20	1100	22	
	Cadomin	74	15/5	60	--	60	1040	62	
	Triassic	4	20/5	3	--	3	1160	3	
	Triassic Solution	99	30/25	52	--	52	1160	60	
	Nisku	1	20/5	1	--	1	1240	1	
	Beaverhill Lake	24	10/30	15	--	15	1210	18	
Kessler	Viking	84	25/5	60	6	54	1020*	55	Gas sold to Trans-Canada Pipe Lines Limited
	Mannville	5	10/5	4	--	4	990	4	
Killam	Viking	4	25/5	3	--	3	1040	3	Presently considered beyond economic reach
	Blairmore	9	15/5	7	--	7	1000	7	
Knappen	Sunburst-Ellis	18	20/10	13	--	13	1000	13	Gas sold to Canadian-Montana Gas Company Ltd.
	Mississippian	8	15/10	6	--	6	1000	6	
Kneller	Blairmore	24	20/5	18	--	18	1100	20	Presently considered beyond economic reach
Knopcik	Doe Creek	17	25/5	12	--	12	1000	12	Gas sold to Northland Utilities Limited
Lac La Biche	Viking	14	25/5	10	--	10	1010	10	Presently considered beyond economic reach
	Blairmore	20	20/5	15	1	14	1010	14	Supplies local utility
Lambert Creek	Wabamun	15	25/10	10	--	10	1050	11	Presently considered beyond economic reach

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO FEB. 28, 1966 BCF	(7) REMAINING MARKETABLE GAS FEB. 28, 1966 BCF	(8) ESTIMATED HEATING VALUE BTU/CU.FT.	(9) REMAINING MARKETABLE GAS (1000 BTU BASIS) BCF	(10) REMARKS
Leafland	Blairmore	15	20/10	11	--	11	1000	11	Presently considered beyond
	Mississippian	3	20/5	2	--	2	1000	2	economic reach
Leafland North	Belly River	11	20/5	8	--	8	1000	8	
	Cardium	5	20/5	4	--	4	1000	4	
Leahurst	Blairmore	37	15/5	30	1	29	1160*	34	Supplies local utility
Leduc-Woodbend	Viking	20	20/5	15	3	12	1070	13	Injected into Nisku and
	Basal Blairmore	85	20/5	65	19	46	1180	54	Leduc gas caps
	Wabamun	1	15/10	1	--	1	1050	1	
	Nisku Associated	37	10/15	28	-8	36	1180	43	
	Nisku Solution	180	25/30	94	67	27	1180	32	Gas sold to Northwestern
	Leduc Associated	420	15/15	300	-12	312	1180	368	Utilities, Limited
	Leduc Solution	170	40/30	70	56	14	1180	17	
Lindbergh	Viking	3	35/5	2	--	2	990*	2	
	Blairmore	18	20/5	14	5	9	1000*	9	Supplies salt plant
Little Bow	Blairmore	20	20/5	15	--	15	1000	15	
Lloydminster	Blairmore	24	15/30	14	12	2	950	2	Supplies local utility
Lone Pine Creek	Basal Blairmore	4	15/10	3	--	3	1020	3	
	Wabamun	190	20/20	120	--	120	1030	124	
	Nisku	5	15/25	3	--	3	1050	3	
	Leduc	59	15/20	40	--	40	1060	42	
Long Coulee	Mannville	18	20/5	14	--	14	1000	14	
Lookout Butte	Mississippian	500	15/5	400	--	400	1040	416	Reservoir being cycled
Lovett River	Blairmore	12	10/5	10	--	10	1040	10	Presently considered beyond
	Mississippian	86	10/10	70	--	70	1040	73	economic reach
Majeau Lake	Blairmore	3	20/5	2	--	2	1000	2	Presently considered beyond
	Mississippian	12	10/10	10	--	10	1070	11	economic reach
Malmo	Viking	7	15/5	6	--	6	1000	6	
	Blairmore	7	15/10	5	--	5	1030	5	
	Devonian	69	20/20	44	--	44	1100	48	Includes area formerly known as Waterglen

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MANYBERRIES	BOW ISLAND	34	20/5	26	20	6	940	6	GAS SOLD TO CANADIAN-MONTANA GAS COMPANY LTD.
MARLBORO	LEDUC	63	15/25	40	--	40	1030	41	
MARSH HEAD CREEK	LEDUC	27	15/35	15	--	15	1050	16	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
MARTEN HILLS	PELICAN	2	35/5	1	--	1	990	1	
	GRAND RAPIDS	5	35/5	3	--	3	990	3	
	WABISKAW	630	25/5	450	--	450	990	446	
	WABAMUN	340	25/5	240	--	240	1000	240	
MATZIWIN	VIKING	11	15/5	9	--	9	1000	9	
	BLAIRMORE	1	15/5	1	--	1	1010	1	
MAZEPPA	MISSISSIPPIAN	20	10/15	15	--	15	1060	16	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
McLEOD	BELLY RIVER	1	15/5	1	--	1	980	1	
	CADOMIN	6	25/10	4	--	4	980	4	
	JURASSIC	7	25/10	5	--	5	1010	5	
MEDICINE HAT	MEDICINE HAT	2400	20/5	1800	381	1419	970*	1380	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED, MANY ISLANDS PIPE LINES LIMITED AND SUPPLIES LOCAL UTILITY
	BOW ISLAND	14	25/5	10	1	9	970	9	
	ELLIS	25	15/5	20	1	19	1000	19	
MEDICINE RIVER	BLAIRMORE ASSOC. AND NON-ASSOC.	160	20/5	120	--	120	1150	138	
	BLAIRMORE SOLUTION	36	40/45	12	--	12	1250	15	
	JURASSIC ASSOC. AND NON-ASSOC.	46	20/5	35	--	35	1020	36	
	JURASSIC SOLUTION	73	35/45	26	--	26	1100	29	
	MISSISSIPPIAN ASSOC. AND NON-ASSOC.	20	15/10	15	--	15	1100	17	
	MISSISSIPPIAN SOLUTION	30	40/45	10	--	10	1200	12	
	LEDUC ASSOCIATED	6	10/20	4	--	4	1000	4	
MILLET	BLAIRMORE	21	20/10	15	--	15	1020	15	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
FIELD OR AREA	ZONE	INITIAL GAS IN PLACE BCF	LOSSES RESERVOIR/SURFACE PER CENT	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED TO FEB. 28, 1966 BCF	REMAINING MARKETABLE GAS FEB. 28, 1966 BCF	ESTIMATED HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS (1000 BTU BASIS) BCF	REMARKS
MINNEHIK-BUCK LAKE	BLAIRMORE	6	25/5	4	--	4	1000	4	GAS SOLD TO ALBERTA AND SOUTHERN GAS COMPANY LTD.
	MISSISSIPPIAN	550	15/10	420	53	367	1130*	415	
MITSUE	GILWOOD SOLUTION	390	45/25	160	--	160	1170	187	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
MOOSE MOUNTAIN	MISSISSIPPIAN	75	20/25	45	--	45	1000	45	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
MORINVILLE	VIKING	3	25/5	2	--	2	1000	2	GAS SOLD TO CANADIAN INDUSTRIAL GAS LIMITED, SUPPLIES LOCAL UTILITY, AND SOLD TO PLAINS-WESTERN GAS LTD.
	BLAIRMORE	140	20/10	100	38	62	1070	66	
MOUNTAIN PARK	TRIASSIC	29	10/5	25	--	25	1090	27	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
NEVIS	BLAIRMORE	65	15/10	50	--	50	1000	50	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED
	DEVONIAN	970	15/15	700	110	590	1000*	590	
NEW NORWAY	VIKING	3	20/5	2	--	2	1000	2	
	BLAIRMORE	11	10/5	9	--	9	1010	9	
NIPISI	GILWOOD SOLUTION	230	45/25	96	--	96	1150	110	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
NORDEGG	TRIASSIC	9	10/10	7	--	7	1000	7	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
	MISSISSIPPIAN	25	10/10	20	--	20	1000	20	
NORMANDVILLE	GETHING	15	15/5	12	--	12	980	12	
	TRIASSIC	4	15/5	3	--	3	1090	3	
	MISSISSIPPIAN	31	15/5	25	2	23	1050	24	SUPPLIES LOCAL UTILITY
OBERLIN	BLAIRMORE	3	20/5	2	2	<1	1090*	<1	SUPPLIES LOCAL UTILITY
OKOTOKS	WABAMUN	420	10/60	150	32	118	1000	118	GAS SOLD TO CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
OLDS	WABAMUN	370	15/20	250	14	236	1050	248	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED

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OYEN	VIKING	43	15/5	35	5	30	980*	29	GAS SOLD TO TRANS-CANADA
	DETRITAL	11	15/5	9	1	8	1010*	8	PIPE LINES LIMITED
PADDLE RIVER	JURASSIC	220	35/10	130	--	130	1070	139	GAS SOLD TO NORTHWESTERN
	MISSISSIPPIAN	30	25/10	20	--	20	1060	21	UTILITIES, LIMITED
PAKOWKI LAKE	BOW ISLAND	15	25/5	10	5	5	940	5	GAS SOLD TO CANADIAN-MONTANA GAS COMPANY LTD.
PARFLESH	VIKING	3	20/5	2	--	2	1000	2	
	MANNVILLE	10	15/5	8	--	8	1000	8	
PARKLAND NORTH-EAST	MISSISSIPPIAN	21	15/15	15	--	15	1010	15	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
PEMBINA	BELLY RIVER ASSOC. AND NON-ASSOC.	79	20/5	60	1	59	1180	70	GAS SOLD TO NORTHWESTERN
	BELLY RIVER SOLUTION	100	55/80	9	2	7	1180	8	UTILITIES, LIMITED
	CARDIUM SOLUTION	4200	55/40	1121	142	979	1170	1150	
	VIKING	11	20/5	8	--	8	1100	9	GAS SOLD TO ALBERTA AND
	BLAIRMORE	260	15/10	200	17	183	1120	205	SOUTHERN GAS CO. LTD.
	JURASSIC	19	15/5	15	--	15	1050	16	
	MISSISSIPPIAN	14	15/15	10	--	10	1050	11	
PENDANT D'OREILLE	BOW ISLAND	180	20/5	140	83	57	940	54	GAS SOLD TO CANADIAN-MONTANA
	MANNVILLE	66	20/5	50	11	39	1000	39	GAS COMPANY LTD.
PENHOLD	VIKING	14	10/5	12	--	12	1020	12	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
PHIL CAN	GETHING	12	20/5	9	--	9	980	9	PRESENTLY CONSIDERED BEYOND
	MISSISSIPPIAN	5	15/5	4	--	4	1050	4	ECONOMIC REACH
PINCHER CREEK	MISSISSIPPIAN	1100	35/25	540	234	306	1020*	312	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED
PINE CREEK	WABAMUN	210	15/50	90	3	87	1050*	91	GAS USED TO MAINTAIN PRESSURE
	LEDUC	1000	50/35	330	104	226	1050*	237	IN WINDFALL FIELD
PINE NORTH-WEST	LEDUC	180	15/35	100	--	100	1050	105	
PLAIN LAKE	VIKING	3	25/5	2	--	2	980	2	PRESENTLY CONSIDERED BEYOND
	BLAIRMORE	28	20/5	21	--	21	1000	21	ECONOMIC REACH
PLOVER LAKE	VIKING	19	15/5	15	--	15	1000	15	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH

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Pouce Coupe	Peace River	190	35/5	120	74	46	1000	46	Gas sold to Westcoast Trans-
	Cadomin	4	15/5	3	--	3	1060	3	mission Company Limited
Pouce Coupe South	Doe Creek	4	40/5	2	1	1	1000	1	Gas sold to Westcoast Trans-
	Peace River	98	30/5	65	44	21	1040	22	Mission Company Limited and
	Gething	25	40/5	14	10	4	1000	4	Peace River Transmission
	Cadomin	2	15/5	2	2	<1	1000	<1	Company Limited
	Triassic	11	20/5	8	--	8	1000	8	
Prevo	Basal Mannville	5	15/10	4	--	4	1020	4	Gas sold to Trans-Canada
	Mississippian	44	15/10	34	5	29	1110*	32	Pipe Lines Limited
Princess	Second White Specks	60	30/5	40	2	38	970*	37	Gas sold to Trans-Canada
	Bow Island	1	25/5	1	--	1	1010	1	Pipe Lines Limited
	Basal Colorado	18	20/5	14	1	13	1020*	13	
	Basal Mannville	110	20/5	80	17	63	1020*	64	
	Jefferson	31	15/5	25	1	24	1030*	25	
Provost	Viking	820	20/5	620	165	455	1030*	469	Gas sold to Trans-Canada
	Blairmore	19	15/5	15	--	15	1000	15	Pipe Lines Limited
Redland	Belly River	2	35/5	1	--	1	1000	1	
	Viking	3	20/5	2	--	2	1000	2	
	Blairmore	19	15/5	15	--	15	1050	16	Gas sold to Canadian Western Natural Gas Company Limited
Redwater	Viking	14	25/5	10	1	9	1040	9	Supplies local utility and gas
	Leduc Solution	230	40/65	49	9	40	1220	49	sold to Canadian Industrial Gas & Oil Ltd.
Red Willow	Viking	13	20/5	10	--	10	1020	10	Presently considered beyond
	Basal Blairmore	8	20/10	6	--	6	1100	7	economic reach
Retlaw	Bow Island	3	25/5	2	--	2	950	2	
	Basal Colorado	7	25/5	5	--	5	1020	5	
	Basal Blairmore	56	20/10	40	1	39	1000	39	Gas sold to Trans-Canada Pipe Lines Limited
Rich	Basal Blairmore	16	15/10	12	--	12	1100	13	

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RICHDALE	VIKING	14	25/5	10	--	10	1010	10	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
	BASAL BLAIRMORE	11	25/5	8	--	8	1050	8	
ROCHESTER	VIKING	5	20/5	4	--	4	1000	4	
	BLAIRMORE	27	25/5	19	--	19	1000	19	
	WABAMUN	6	10/5	5	--	5	1070	5	
ROLLING HILLS	BOW ISLAND	19	15/5	15	--	15	970	15	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
	BASAL COLORADO	12	15/5	10	--	10	1030	10	SUPPLIES LOCAL UTILITY
ROWLEY	BASAL BELLY RIVER	5	20/5	4	--	4	1000	4	
	VIKING	9	10/5	8	--	8	1040	8	
	MANNVILLE	13	15/5	11	--	11	1070	12	
	MISSISSIPPIAN ASSOC. AND NON-ASSOC.	47	10/10	38	--	38	1080	41	
RYCROFT	GETHING	16	15/5	13	3	10	1040	10	SUPPLIES LOCAL UTILITY
ST. ALBERT-BIG LAKE	VIKING	3	20/5	2	--	2	1070*	2	GAS SOLD TO CANADIAN INDUSTRIAL GAS LIMITED
	BLAIRMORE	150	15/5	120	54	66	1070*	71	
ST. PAUL	BLAIRMORE	5	20/5	4	3	1	1000*	1	SUPPLIES LOCAL UTILITY
SADDLE HILLS	PEACE RIVER	48	30/5	32	--	32	1020	33	
	GETHING	3	20/5	2	--	2	980	2	
	PERMO-PENN	22	20/15	15	--	15	1030	15	
SAMSON	BLAIRMORE ASSOC. AND SOLUTION	17	25/5	12	4	8	1040	8	GAS SOLD TO NORTHWESTERN UTILITIES, LIMITED
SARCEE	MISSISSIPPIAN	210	15/15	150	24	126	1050	132	GAS SOLD TO CANADIAN WESTERN NATURAL GAS COMPANY LIMITED
SAVANNA CREEK	MISSISSIPPIAN	590	10/25	400	19	381	1020	388	GAS SOLD TO WESTCOAST TRANSMISSION COMPANY LIMITED
SEDALIA	VIKING	130	20/5	100	4	96	1010*	97	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED
	BLAIRMORE	1	25/5	1	--	1	1010	1	
SEIU LAKE	VIKING	1	25/5	1	--	1	1000	1	
	MANNVILLE	17	15/5	14	--	14	1000	14	

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO FEB. 28, 1966 BCF	(7) REMAINING MARKETABLE GAS FEB. 28, 1966 BCF	(8) ESTIMATED HEATING VALUE BTU/CU.FT.	(9) REMAINING MARKETABLE GAS (1000 BTU BASIS) BCF	(10) REMARKS
Sibbald	Viking	33	20/5	25	9	16	960*	15	Gas sold to Trans-Canada
	Basal Colorado	13	20/5	10	--	10	970	10	Pipe Lines Limited
	Banff	1	20/5	1	--	1	1050	1	
Simonette	Cadomin	20	15/10	15	--	15	1060	16	Presently considered beyond
	Wabamun	140	10/35	80	--	80	1070	86	economic reach
	Leduc Solution	270	45/45	81	--	81	1020	83	
Smith Coulee	Bow Island	49	25/5	35	17	18	930	17	Gas sold to Canadian-Montana Gas Company Ltd.
Standard	Viking	26	20/5	20	--	20	1000	20	
Steen River	Slave Point	13	10/15	10	--	10	1070	11	Presently considered beyond economic reach
Steep Creek	Gething	6	15/5	5	--	5	1020	5	Presently considered beyond
	Triassic	7	15/10	5	--	5	1030	5	economic reach
	Permo-Penn	12	10/10	10	--	10	1030	10	
Stettler	Viking	4	25/5	3	--	3	1020	3	Gas used for Compressor fuel
	Nisku Solution	20	45/45	6	2	4	1130	5	Gas sold to Northwestern Utilities,
	Leduc Solution	13	45/45	4	1	3	1140	3	Limited
Stolberg	Mississippian	87	10/10	70	--	70	1040	73	Presently considered beyond economic reach
Strathmore	Belly River	7	20/5	5	1	4	1000	4	Gas sold to Canadian Western
	Viking	7	20/5	5	--	5	1000	5	Natural Gas Company Limited
	Mississippian	1	20/5	1	--	1	1080	1	
Sturgeon Lake	Gething	12	15/5	10	--	10	1000	10	Presently considered beyond
	Gilwood	3	25/5	2	--	2	1100	2	economic reach
Sturgeon Lake South	Gething	16	15/5	13	--	13	1000	13	
	Cadomin	6	15/5	5	--	5	1060	5	
	Triassic Associated	5	10/5	4	--	4	1180	5	
	Triassic Solution	15	35/70	3	--	3	1180	4	
	Wabamun	7	10/25	5	--	5	1070	5	
	Leduc Associated	7	10/25	5	--	5	1080	5	
	Leduc Solution	270	45/45	83	10	73	1080	79	Gas sold to Canadian Utilities Limited

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO FEB. 28, 1966 BCF	(7) REMAINING MARKETABLE GAS FEB. 28, 1966 BCF	(8) ESTIMATED HEATING VALUE BTU/CU.FT.	(9) REMAINING MARKETABLE GAS (1000 BTU BASIS) BCF	(10) REMARKS
STURGEON LAKE SOUTH GENERAL AREA	GETHING	80	15/5	65	--	65	1000	65	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
	CADOMIN	31	15/5	25	--	25	1060	27	
	TRIASSIC	6	15/5	5	--	5	1180	6	
	PERMO-PENN	3	20/5	2	--	2	1030	2	
SUNDRE	VIKING	6	20/10	4	--	4	1020	4	
	BLAIRMORE	16	15/10	12	--	12	1020	12	
	ELKTON ASSOCIATED	21	15/15	15	-4	19	1070	20	
	ELKTON SOLUTION	77	50/35	25	4	21	1100	23	GAS INJECTED INTO GAS CAP
SUNNYNOOK	BLAIRMORE	12	15/5	10	--	10	1030	10	FORMERLY INCLUDED IN CESSFORD AREA
SUNSET LAKE	BLAIRMORE	13	20/5	10	--	10	1000	10	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
	CADOMIN	7	10/5	6	--	6	1030	6	
SWALWELL	VIKING	4	20/5	3	--	3	1000	3	
	MISSISSIPPIAN	38	15/5	31	--	31	1100	34	
SWAN HILLS	GETHING	1	10/5	1	--	1	1050	1	
	BEAVERHILL LAKE SOLUTION	1300	55/60	240	8	232	1120	260	GAS SOLD TO NORTHWESTERN UTILITIES, LIMITED
SWAN HILLS SOUTH	BEAVERHILL LAKE SOLUTION	570	55/40	154	4	150	1120	168	GAS SOLD TO NORTHWESTERN UTILITIES, LIMITED
SYLVAN LAKE	VIKING	4	15/5	3	--	3	1010	3	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED
	BLAIRMORE	380	15/10	290	11	279	1100	307	
	DETRITAL	8	20/10	6	--	6	1100	7	
	JURASSIC ASSOC. AND NON-ASSOC.	62	20/10	45	--	45	1020	46	
	JURASSIC SOLUTION	24	40/45	8	--	8	1100	9	
	MISSISSIPPIAN	100	20/10	75	3	72	1100	79	
	MISSISSIPPIAN SOLUTION	42	40/40	15	--	15	1200	18	
	LEDUC ASSOCIATED	35	20/10	25	--	25	1020	26	
	LEDUC SOLUTION	14	35/45	5	--	5	1100	6	
TABER SOUTH	BOW ISLAND	17	30/5	11	--	11	1000	11	

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
FIELD OR AREA	ZONE	INITIAL GAS IN PLACE BCF	LOSSES RESERVOIR/SURFACE PER CENT	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED TO FEB. 28, 1966 BCF	REMAINING MARKETABLE GAS FEB. 28, 1966 BCF	ESTIMATED HEATING VALUE BTU/CU.FT.	REMAINING MARKETABLE GAS (1000 BTU BASIS) BCF	REMARKS
Tangent	Cadotte	14	30/5	9	--	9	1010	9	Presently considered beyond
	Gething	79	20/5	60	--	60	1000	60	economic reach
	Triassic	53	20/5	40	--	40	1180	47	
Tawatinaw	Mannville	15	15/5	12	--	12	1000	12	
	Devonian	1	15/5	1	--	1	1010	1	
Thorhild	Mannville	12	15/5	10	--	10	1000	10	Formerly included in Tawatinaw Area
Three Hills Creek	Belly River	9	15/5	7	--	7	970	7	Gas sold to Trans-Canada
	Viking	8	20/5	6	--	6	1000	6	Pipe Lines Limited
	Mississippian	210	10/10	170	13	157	1110*	174	
	Leduc	10	20/15	7	--	7	1100	8	
Turin	Bow Island	13	20/5	10	--	10	970	10	Presently considered beyond
	Basal Blairmore	35	10/5	30	--	30	1020	31	economic reach
	Ellis	5	15/5	4	--	4	1070	4	
	Mississippian	3	15/10	2	--	2	1050	2	
Turner Valley	Mississippian Associated	1500	10/70	410	279	131	1110	145	Gas sold to Canadian Western
									Natural Gas Company Limited
	Mississippian Solution	1400	45/55	350	275	75	1110	83	and supplies local utility
Twining North	Mannville	7	20/5	5	--	5	1100	6	
	Mississippian Associated	40	20/5	30	--	30	1110	33	
	Mississippian Solution	16	40/15	8	--	8	1110	9	
Two Creek	Triassic	12	10/5	10	--	10	1090	11	Presently considered beyond economic reach
Usona	Blairmore	12	10/5	10	--	10	1110	11	Presently considered beyond economic reach
Verger	Bow Island	3	25/5	2	--	2	1100	2	
	Basal Colorado	7	25/5	5	1	4	1060	4	Gas sold to Trans-Canada
	Basal Mannville	74	15/5	60	2	58	1050	61	Pipe Lines Limited
	Mississippian	3	15/10	2	--	2	1070	2	

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO FEB. 28, 1966 BCF	(7) REMAINING MARKETABLE GAS FEB. 28, 1966 BCF	(8) ESTIMATED HEATING VALUE BTU/CU.FT.	(9) REMAINING MARKETABLE GAS (1000 BTU BASIS) BCF	(10) REMARKS
Viking-Kinsella	Viking	950	15/5	770	397	373	1000*	373	Gas sold to Northwestern
	Blairmore	79	20/5	60	14	46	1000	46	Utilities, Limited and supplies
	Devonian	18	20/5	14	4	10	990*	10	local utility
Virginia Hills	Blairmore	9	10/5	8	--	8	1040	8	
	Permian	20	15/10	15	--	15	1160	17	
	Beaverhill Lake								
	Solution	230	60/60	36	2	34	1070	36	Gas sold to Northwestern
	Slave Point	3	25/20	2	--	2	1070	2	Utilities, Limited
Vulcan	Mannville	26	20/5	20	--	20	1000	20	Formerly known as Kirkcaldy
	Mississippian	23	20/20	15	--	15	1010	15	Area
Wainwright	Viking	5	15/5	4	--	4	980	4	
	Blairmore Assoc. and Non-Assoc.	36	20/30	20	--	20	940	19	
Waskahigan	Dunvegan	25	10/10	20	--	20	1100	22	Presently considered beyond economic reach
Waterton	Mississippian	2200	15/40	1130	92	1038	1040*	1080	Gas sold to Alberta and
	Devonian	270	20/30	150	16	134	1020	137	Southern Gas Co. Ltd.
Watts	Viking	3	20/5	2	1	1	1030*	1	Supplies local utility
	Mississippian	1	20/5	1	--	1	1070	1	
Wayne-Rosedale	Belly River	7	20/5	5	--	5	1000	5	Gas sold to Trans-Canada Pipe
	Viking	220	15/5	178	15	163	1090*	178	Lines Limited, Canadian Western
	Blairmore	240	15/5	193	21	172	1120*	193	Natural Gas Company Limited and supplies local utility
West Drumheller	Basal Blairmore	7	15/5	6	--	6	1100	7	
	Nisku Associated	9	10/15	7	--	7	1090	8	
Westerose	Blairmore	7	20/5	5	--	5	1020	5	
	Leduc Associated	130	10/20	90	-9	99	1070	106	
	Leduc Solution	140	35/15	79	9	70	1100	77	Gas injected into gas cap
Westerose South	Wabamun	7	10/10	6	--	6	1090	7	Gas sold to Trans-Canada Pipe
	Leduc	1700	10/15	1300	250	1050	1070*	1120	Lines Limited and Alberta and Southern Gas Co. Ltd.

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO FEB. 28, 1966 BCF	(7) REMAINING MARKETABLE GAS FEB. 28, 1966 BCF	(8) ESTIMATED HEATING VALUE BTU/CU.FT.	(9) REMAINING MARKETABLE GAS (1000 BTU BASIS) BCF	(10) REMARKS
WESTLOCK	VIKING	310	15/5	250	24	226	1060*	240	GAS SOLD TO CANADIAN INDUSTRIAL GAS LIMITED AND SUPPLIES LOCAL UTILITY
	BASAL BLAIRMORE	4	20/5	3	--	3	1100	3	
WEST PRAIRIE	CADOTTE	18	10/5	15	--	15	1040	16	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
	BLUESKY	6	10/5	5	--	5	990	5	
WHITELAW	GETHING	31	15/5	25	5	20	1020	20	SUPPLIES LOCAL UTILITY
	TRIASSIC	33	20/5	25	--	25	1090	27	
WILDCAT HILLS	MISSISSIPPIAN	810	15/20	550	62	488	1050*	512	GAS SOLD TO ALBERTA AND SOUTHERN GAS CO. LTD.
WILDHORSE CREEK	MISSISSIPPIAN	150	15/20	100	--	100	940	94	
WILDMERE	BLAIRMORE	37	20/5	28	9	19	960*	18	SUPPLIES LOCAL UTILITY
WILDUNN CREEK	VIKING	35	25/5	25	2	23	1010	23	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED
WILLESDEN GREEN	BELLY RIVER	4	20/5	3	--	3	1000	3	
	CARDIUM	12	20/5	9	--	9	1100	10	
	CARDIUM SOLUTION	260	65/35	59	1	58	1100	64	GAS SOLD TO ALBERTA AND SOUTHERN GAS CO. LTD.
	BASAL BLAIRMORE	20	10/15	15	--	15	1100	17	
WILLINGDON	VIKING	3	25/5	2	--	2	980	2	GAS SOLD TO WESTERN MINERALS LTD. AND SUPPLIES LOCAL UTILITY
	MANNVILLE	15	25/5	11	2	9	990	9	
	LEDUC	11	10/5	9	6	3	1000*	3	
WILSON CREEK	PEKISKO	23	10/5	20	--	20	1090	22	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH
	BANFF	18	10/5	15	--	15	1080	16	
WIMBORNE	VIKING	1	25/5	1	--	1	1020	1	
	MISSISSIPPIAN	1	10/10	1	--	1	1100	1	
	NISKU	3	20/15	2	--	2	1160	2	
	NISKU SOLUTION	5	30/45	2	--	2	1160	2	
	LEDUC ASSOCIATED	320	10/30	200	9	191	1000	191	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED
	LEDUC SOLUTION	110	50/45	30	--	30	1000	30	
WINDFALL	VIKING	13	25/5	9	--	9	1030	9	RESERVOIR BEING CYCLED. GAS SOLD TO ALBERTA AND SOUTHERN GAS CO. LTD., PRESSURE MAINTAINED BY PINE CREEK GAS
	MISSISSIPPIAN	5	15/5	4	--	4	1040	4	
	LEDUC	820	10/35	480	32	448	1080*	484	
WINNIFRED	BOW ISLAND	16	20/5	12	--	12	1000	12	

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO FEB. 28, 1966 BCF	(7) REMAINING MARKETABLE GAS FEB. 28, 1966 BCF	(8) ESTIMATED HEATING VALUE BTU/CU.FT.	(9) REMAINING MARKETABLE GAS (1000 BTU BASIS) BCF	(10) REMARKS
Wintering Hills	Belly River	1	25/5	1	--	1	1000	1	
	Viking	38	20/5	29	--	29	1010	29	Includes area formerly known as Hutton
	Blairmore	41	25/10	28	--	28	1070	30	
	Mississippian	1	25/10	1	--	1	1030	1	
Wizard Lake	Belly River	1	25/5	1	--	1	1050	1	
	Viking Assoc. and Non Assoc.	1	15/10	1	--	1	1070	1	
	Blairmore	15	20/15	10	10	<1	1120	<1	Gas sold to Northwestern Utilities, Limited
	Leduc Solution	230	40/25	105	15	90	1250	112	
Woking	Peace River	5	10/5	4	--	4	1040	4	Supplies local utility
	Spirit River	3	20/5	2	--	2	1040	2	
	Bluesky	4	20/5	3	--	3	1040	3	
	Permo-Penn	3	20/5	2	--	2	1060	2	
	Mississippian	3	25/5	2	--	2	1070	2	
Wolf Lake	Cadomin	13	10/5	11	--	11	1060	12	Presently considered beyond economic reach
Wood River	Basal Blairmore	42	10/10	34	5	29	1090	32	Gas sold to Trans-Canada Pipe Lines Limited
Worsley	Leduc	300	20/5	230	40	190	1070	203	Gas sold to Westcoast Trans-Mission Company Limited and Supplies Local Utility
Zama Lake	Elk Point	16	20/5	12	--	12	1110	13	Presently considered beyond economic reach
	SUB TOTAL			42,481	5,554	36,927		39,202	
	OTHER RESERVES								
	Less than 10 Bcf			876	--	876		931	
	Confidential Pools			153	--	153		165	
	TOTAL RESERVES, FEB. 28, 1966			43,510	5,554	37,956		40,298	
	TOTAL RESERVES WITHIN ECONOMIC REACH			40,628	5,554	35,074		37,245	
	TOTAL RESERVES BEYOND ECONOMIC REACH			2,882	--	2,882		3,053	

* MEASURED HIGHER HEATING VALUE

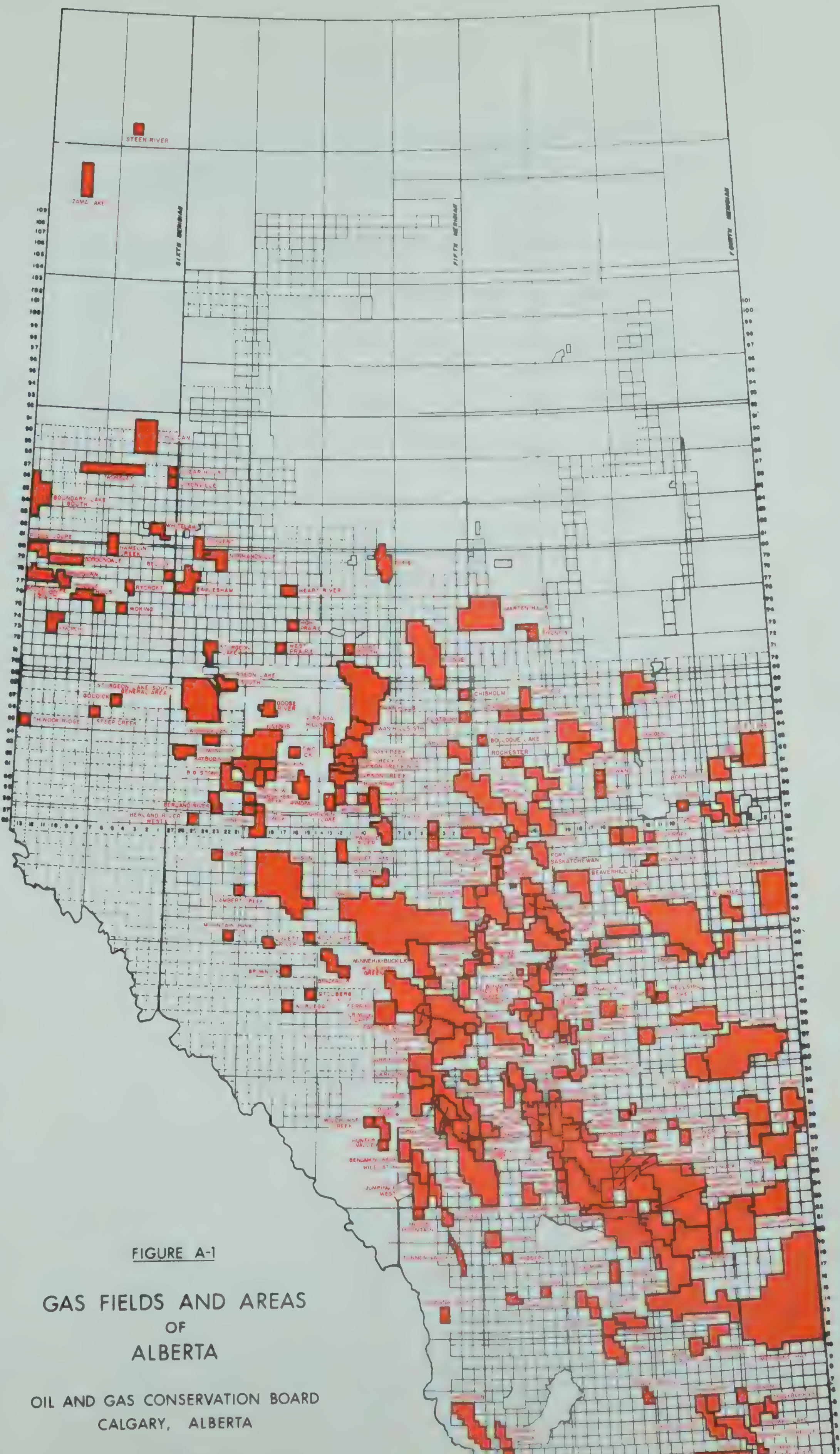

FIGURE A-1

GAS FIELDS AND AREAS OF ALBERTA

OIL AND GAS CONSERVATION BOARD
CALGARY, ALBERTA

JULY, 1966

APPENDIX B

THE TRENDS IN EXPLORATION FOR AND THE GROWTH OF RESERVES OF GAS IN ALBERTA

Trans-Canada at the hearing of its application did not present a detailed study of the trends in gas reserve growth in the Province. However, it did present a brief analysis of the growth of reserves over the last two years and on a long term basis. The growth rates as determined by Trans-Canada were based on the Board's estimate of initial marketable gas reserves for the Province as of June 30, 1955 and December 31, 1963, and on Trans-Canada's estimate of initial marketable gas reserves as of February 28, 1966. The analyses presented by Trans-Canada showed that the growth rate of initial marketable gas reserves has averaged 3.2 trillion cubic feet per year over the past two years. It also showed that the average growth rate over the past ten years has been 2.6 trillion cubic feet per year. In its assessment of the gas surplus to Alberta's requirements and the existing permit commitments, Trans-Canada used the long term growth rate of 2.6 trillion cubic feet per year.

The Alberta Division of CPA in its submission presented a graph of "Alberta Recoverable Gas Reserves Credited Back To Year of Discovery" for the period 1947 to 1965 inclusive. The Alberta Division's interpretation of the graph for the period 1954 to 1962 indicated a long term gas discovery rate of 2.7 trillion cubic feet per year on a wellhead recoverable basis or 2.5 trillion cubic feet per year on a marketable basis. This

discovery rate as estimated by the Alberta Division of CPA is not determined in precisely the same manner as is the long term growth rate referred to by Trans-Canada and used by the Board, but it does serve as an approximate check of it.

Views of the Board

The Board in OGCB Report 66-18[1] reviewed in detail the long term trend in the growth of gas reserves in Alberta as of December 31, 1965. The report shows that the average annual growth in initial gas reserves varies depending on the number of past years included in the analysis. However, it does indicate a continuation of the long term rate of growth at about 2.5 trillion cubic feet per year, the rate used by the Board over the past several years. Since the additional reserve data the Board now has covers a period of only two months and because the growth in reserves over this period has been at a rate close to the previously established long term rate, the Board has not considered it necessary to make a further detailed analysis and has decided to continue to use the growth rate of 2.5 trillion cubic feet per year.

As shown in Appendix A of this report, the Board estimates the initial marketable gas reserves in the Province as of February 28, 1966, to be 43.5 trillion cubic feet. In OGCB

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(1) Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur, Province of Alberta. December 31, 1965.

Report 64-8[2] the Board estimated the initial marketable gas reserves of the Province as of December 31, 1963 to be 36.7 trillion cubic feet. This indicates that the reserves have grown by some 6.8 trillion cubic feet over the past 26 months or at a rate of some 3.1 trillion cubic feet per year. Consequently, the Board, in keeping with its policy of using the lesser of the growth rate over the previous two years or the long term growth rate, will use in its surplus calculations a growth rate of 2.5 trillion cubic feet per year.

Ultimate Reserves

At the hearing of Trans-Canada's application, the Alberta Division of CPA included in its submission a brief reference to the ultimate reserves of gas in Alberta. The Alberta Division referred to a study it placed before the Board at the hearing of the application of Alberta and Southern in July, 1964, in which it estimated the ultimate marketable gas reserves of the Province at 120 trillion cubic feet, and stated that it still considers this estimate to be valid.

Trans-Canada did not itself submit evidence respecting the ultimate reserves in the Province. However, in answer to a question regarding another matter, Mr. Horte stated that he believes the ultimate reserves number should be greater than the 100 trillion cubic feet estimated by the Board.

As is discussed in the recent OGCB Report 66-18, the Board

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(2) Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur, Province of Alberta. December 31, 1963.

has made several studies respecting the ultimate marketable reserves of gas in the Province. These include a projection of the long term growth rate, a projection of the reserves discovered per exploratory well drilled and an estimate based upon the volume of favourable sediments. The Board has also received considerable evidence from industry over the past several years as to the ultimate gas reserves in the Province, including the submission referred to by the Alberta Division of CPA at the recent hearing. On the basis of the estimates available from industry and its own studies, the Board remains convinced that an ultimate gas reserve estimate for the Province of approximately 100 trillion cubic feet is reasonable.

APPENDIX C

ALBERTA GAS REQUIREMENTS AND PRESENT PERMIT COMMITMENTS

Introduction

Trans-Canada did not present new evidence as to Alberta's thirty-year requirements, but rather updated the Board's 1964 forecast published in OGCB Report 64-11[1]. The Utility Companies' submission included a new forecast of Alberta gas requirements for the period 1966 to 1995, which replaced their previous projection. Subsequently to the hearing, the Board staff prepared a new forecast to supersede that discussed in OGCB Report 64-11.

Each forecast and the Board's own assessment of requirements are described separately below. In all cases, the period of assessment is January 1, 1966 to December 31, 1995.

Trans-Canada Pipe Lines Limited

Trans-Canada adopted the Board's 1964 forecast, modified to relate it to the period 1966 to 1995, since the Board forecast embraced the thirty-year interval 1964 to 1993. The adjustment was made by applying the Board's total average annual growth rate of 3.7 per cent to the Board's estimate of demand in 1993 to compute requirements for 1994 and 1995. These were added to the Board's thirty-year total, from which resulting figure Trans-Canada deducted 1964 and 1965 estimated Alberta

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(1) Report on the Applications of Trans-Canada Pipe Lines Limited and Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. November 1964.

consumption. The numbers are shown below:

		Bcf
Board estimate of requirements 1964 to 1993		10,339.7
Less estimated 1964 Alberta consumption	185.8	
estimated 1965 Alberta consumption	192.7	
	378.5	
Add estimate for 1994 (1.037 x 533.6*)	553.3	
estimate for 1995 (1.037 x 553.3)	573.8	
	1,127.1	
Net Addition		748.6
Total		11,088.3

* Board estimated 1993 requirements.

Trans-Canada thus submitted Alberta's total requirements for the period 1966 to 1995 would amount to some 11,088 billion cubic feet.

Utility Companies

The Utility Companies' forecast, excluding contingency allowances, employed a distinction between the requirements for their service areas and requirements for the remainder of the Province. Within each area four separate categories of consumption were considered: domestic, commercial, basic industrial and special industrial. Generally, special industrial consumption was defined to embrace those loads of sufficient magnitude to warrant individual attention.

1. Requirements for Areas Served by Canadian Western Natural Gas Limited and Northwestern Utilities, Limited

A detailed forecast of domestic, commercial and basic industrial demand, based on anticipated population growth and per capita rates of consumption within these areas, was prepared.

Population increases for the Calgary and Edmonton areas of 13,000 per year and 15,000 per year respectively were postulated until 1980, after which point a 2.5 per cent per year average annual rate of growth was employed. The latter rate was intended to arrest the decline in growth rate implied by the linear pattern at a level somewhat above the 'natural' increase. Other communities in the Canadian Western system were expected to grow by 2,500 per year, while the corresponding figure for the Northwestern Utilities system was 3,000 per year. These linear increases were projected only to the year in which they represented an annual growth rate of two per cent - 1976 for the CWNG system and 1982 for NUL - after which time a two per cent rate was anticipated to prevail. Generally, the expansion in population served in the other communities category was designed to accomodate extensions of service to new communities in addition to growth in existing communities. However, in 1966 specific provision was made for new communities served, to the extent of seven such centres in the Northwestern system. Hence, total population served by the Utility Companies was anticipated to rise from 934,500 in 1966 to 2,005,000 in 1995, representing an overall compound rate of growth of 2.67 per cent per year.

Gas requirements for the domestic, commercial and basic

industrial categories of demand were computed by applying estimated per capita consumption rates to the forecast of population.

An analysis of historical rates of domestic per capita consumption revealed no apparent trend, and the average value based on the past ten years of 47.5 thousand cubic feet per year per capita was adopted for the entire forecast period. Domestic demand was thus expected to rise from 44.4 billion cubic feet in 1966 to 95.2 billion cubic feet in 1995, with thirty-year requirements amounting to 2049 billion cubic feet.

Recent years had exhibited a rising trend in commercial per capita consumption, which was anticipated to continue over the next few years. Commercial per capita consumption thus was expected to increase from 38.5 thousand cubic feet per year in 1966 to 39.7 thousand cubic feet in 1970, and to remain constant at that level thereafter. The rise was intended to reflect an increasing degree of commercial development, as evidenced by the construction of office and apartment blocks, primarily in Calgary and Edmonton. Commercial consumption was forecast to increase from 36.0 billion cubic feet in 1966 to 79.6 billion cubic feet in 1995, with the thirty-year requirements totalling 1710 billion cubic feet.

Basic industrial requirements per capita were anticipated to grow from 12.6 thousand cubic feet in 1966 to 13.5 thousand cubic feet in 1970, in continuation of the rising trend in recent years, and to be maintained at a constant level thereafter.

Consequently, basic industrial demand was estimated to rise from 11.8 billion cubic feet in 1966 to 27.1 billion cubic feet in 1995, with thirty-year requirements of 581 billion cubic feet.

Special industrial demand consisted of sixteen large industrial loads for which individual estimates were made. Ten of these are located in the Northwestern Utilities area and six in the Canadian Western system. Increased consumption was projected for five of these loads, on the basis of present definitive plans. Special industrial demand was expected to increase from 39.7 billion cubic feet in 1966 to 63.0 billion cubic feet in 1995, with the thirty-year requirements totalling 1,697 billion cubic feet. Further growth in the industrial category was provided for by the Utility Companies' contingency allowance, discussed later.

Combining the domestic, commercial, basic and special industrial categories of demand, but excluding contingency allowances, the Utility Companies anticipated total requirements for their service areas would grow from 131.9 billion cubic feet in 1966 to 264.9 billion cubic feet in 1995. Thirty-year requirements amounted to some 6036 billion cubic feet.

2. Requirements for Remainder of Province

Domestic, commercial and basic industrial requirements for remaining areas in the Province, other than Peace River which was considered separately, were forecast to grow at a rate corresponding to the anticipated population increase for urban areas in the Utility Companies' system, excluding the

Calgary and Edmonton metropolitan areas. This procedure implied constant per capita rates of consumption for each category, which were justified by the Utility Companies on the ground that the postulated increase in per capita commercial and basic industrial sales in their service areas pertained primarily to the Calgary and Edmonton centres.

Based on studies by Northland Utilities Limited, an associate company, domestic, commercial and basic industrial demand in the Peace River area was anticipated to grow at five per cent per year until 1978 and three per cent thereafter.

Twelve special industrial loads in the remainder of the Province were individually appraised, based on interviews. Future increases were provided for six of these loads in accordance with known firm plans.

Hence, domestic, commercial and basic industrial requirements for the remainder of the Province were expected to increase respectively from levels of 6.3, 3.3 and 3.1 billion cubic feet in 1966 to 12.8, 7.2 and 5.9 billion cubic feet respectively by 1995; with total thirty-year requirements of 282, 154 and 132 billion cubic feet. Special industrial consumption was anticipated to grow from 44.5 billion cubic feet in 1966 to 62.3 billion cubic feet by 1995, with a thirty-year total of 1658 billion cubic feet.

Total requirements for the remainder of the Province, excluding provision for contingency, were therefore estimated to rise from 57.2 billion cubic feet in 1966 to 88.2 billion

cubic feet by 1995 and over the thirty-year period were estimated to amount to 2,226 billion cubic feet.

3. Total Provincial Requirements

In addition to the sum of estimated requirements for the Utility Companies' service areas and the remainder of the Province, the Utility Companies' total Provincial requirements included an industrial contingency allowance and a special provision for anticipated consumption by a scheme for processing iron ore in the Peace River region.

The industrial contingency allowance commenced in 1968 at a level of 4 billion cubic feet, increasing each subsequent year by four billion cubic feet, and was intended to cover expansion in existing loads not already accounted for by the special industrial category and new developments.

The total contingency allowance over the forecast period amounted to 1,624 billion cubic feet. The year by year contingency provisions were based on an average distribution of this postulated aggregate amount, deemed reasonable to provide over the thirty-year period, and were not intended to reflect actual anticipated annual requirements. The Utility Companies emphasized the fact that almost three-quarters of their contingency may be absorbed by developments currently under investigation.

The requirements for the Peace River Mining & Smelting Ltd. scheme for processing iron ore was the amount of 2,072 billion cubic feet submitted by that company as their

anticipated consumption for the period 1969 to 1995.

In summary, the Utility Companies estimated the total Provincial requirements for gas would increase from 189.1 billion cubic feet in 1966 to 607.1 billion cubic feet by 1995, with thirty-year requirements totalling 11,958 billion cubic feet.

Board Staff Forecast

Prior to preparing its forecast, the Board staff reviewed the forecast of Provincial population previously adopted by the Board and published in OGCB Report 64-11. This review disclosed an increasing divergence between the forecast and the estimates of actual population compiled by the Alberta Government and the Dominion Bureau of Statistics such that the forecast exceeded the Government estimates by some 55,000 in 1965. Most of the difference appeared to be attributable primarily to a somewhat lower actual level of urban growth than had been anticipated in the forecast. In view of this tendency, the Board staff decided to revise the forecast on an interim basis, pending a more complete investigation upon the results of the 1966 census. In revising the forecast, for purposes of forecasting future domestic and commercial gas requirements, a distinction was observed between the estimated future population consuming gas as a principal heating fuel and the remainder. The revised projection was compiled on a census division basis, similarly to the previous forecast.

Overall, the revised projection showed a growth in total mid-year population from 1,497,000 in 1966 to 3,006,000 by 1995, with an average annual growth rate between these values of 2.4 per cent; the corresponding numbers anticipated under the previous study were 1,548,000, 3,397,000 and 2.8 per cent respectively. The reduction is mainly attributable to a downward revision in the estimated rate of future urban growth. The forecast of population served by gas within each census division was generally prepared by applying expected levels of urban population growth to the estimated population served in 1965, whereas the pattern of growth in the non-gas consuming sector reflected anticipated rural trends. This approach was subject to appropriate variation where urban communities were not served by gas or where extensions in gas service would result in transference between categories. Extensions in gas service to communities not now served were based on a relatively optimistic assessment of feasibility.

Provincial population located in areas served by gas was expected to increase from 1,086,000 in 1966 to 2,658,000 in 1995, representing an average annual growth rate of 3.2 per cent. The difference between this figure and the total anticipated Provincial population growth rate of 2.4 per cent is primarily attributable to the expected above average growth in urban areas, reflecting immigration and continued rural migration to towns, the transference of communities to gas served areas following extensions of service and an approximately

constant rural population.

The following categories of demand were considered by the Board staff in preparing its forecast: domestic, commercial and industrial. The forecast of population served with gas was principally used in determining the projection of domestic and commercial requirements, and to a lesser extent, in estimating a portion of industrial demand. Each category is discussed separately below.

1. Domestic Demand

To conform to the population projection, the forecast of domestic demand was made on a census division basis. Requirements were estimated by applying anticipated per capita consumption rates to the forecast of population served by gas. Three patterns of projection of per capita gas consumption by census division were identified: constant, declining and appreciating levels. Constant levels were adopted where little evidence of trends existed. Declining levels were anticipated where major metropolitan centres were concerned, to reflect the transference of customers from the domestic to commercial categories resulting primarily from construction of apartment blocks, and the increased use of electricity. Appreciating levels were postulated where scope existed for increased use of gas. Overall average domestic per capita consumption rates for the Province as a whole were expected to decline gradually from an estimated level of some 46 thousand cubic feet per year in 1966 to 44.2 thousand cubic feet per year by 1995.

Domestic consumption was thus forecast to increase from 50.0 billion cubic feet in 1966 to 117.4 billion cubic feet in 1995, with total thirty-year requirements amounting to 2,445 billion cubic feet.

2. Commercial Demand

Similarly to the forecast of domestic demand, commercial consumption was forecast for each census division, by application of anticipated per capita rates to the projection of population served by gas. All census divisions were expected to exhibit increases in per capita rates, then to stabilize at a higher level. The amount of the increases and the time at which stabilization would be achieved varied by census division. In particular, the increases in per capita rates postulated for the two census divisions which include the Calgary and Edmonton metropolitan areas reflect to some extent the obverse of the decline in domestic per capita rates, with the transference between the domestic and commercial categories attributable to apartment developments increasing commercial per capita consumption. Provincial average per capita consumption was expected to increase from 35.7 thousand cubic feet per year in 1966 to 36.8 thousand cubic feet per year by 1995.

In total, commercial demand is anticipated to rise from 38.8 billion cubic feet in 1966 to 97.8 billion cubic feet by 1995, with the thirty-year requirements amounting to 1,987 billion cubic feet.

3. Industrial Requirements

The Board staff considered two categories of industrial

gas requirements; basic and special, to the total of which it added amounts relating to 'other'industrial requirements and contingencies.

Basic Industrial. Population was not utilized directly in forecasting the basic industrial requirements, and hence this category was not projected, as were the domestic and commercial categories, by census division. Basic industrial demand was forecast by major utility systems, having regard for past trends and current expectations. The reasonability of the requirements so predicted was confirmed by computing per capita consumption rates.

The Medicine Hat area in the past exhibited markedly higher basic industrial gas consumption, and an average growth rate of 2.5 per cent was postulated for this region. This rate was slightly higher than the anticipated growth in population, and hence per capita consumption was estimated to rise. Growth in the Canadian Western and Northwestern Utilities systems was expected to average 3.7 per cent and 4.2 per cent per year respectively, with the higher rate in the Northwestern Utilities area designed to reflect a reduction in the differential between the levels of per capita consumption between the two areas. Both growth rates imply gradually rising per capita consumption over the forecast period. Growth in the Northland Utilities' system was expected to approximate 2.5 per cent per year throughout the forecast.

Total basic industrial requirements were thus anticipated

to rise from 14.2 billion cubic feet in 1966 to 40.9 billion cubic feet by 1995, with thirty-year requirements amounting to 786 billion cubic feet.

These amounts are not directly comparable to the Utility Companies' forecast, since the classifications employed by the Board staff and by the Utility Companies for the separation of special and basic industrial were not identical.

Special Industrial. Since the analysis relating to special industrial requirements, as the name implies, concerns specific plants, these were forecast individually, based on interviews with personnel of each of the major industries or plants in the group. The estimated requirements included anticipated increases in consumption where extensions to plants, phased in accordance with industry expectations, were indicated as more than probable. Furthermore, special industrial loads were also increased where it seemed reasonable that such requirements would rise in the future with expected increases in market demand factors - such as the underlying anticipated growth in population. This approach results in a somewhat greater number of industrial loads increasing over the forecast period than postulated by the Utility Companies, who intended to compensate for some of these increases in special industrial loads by their contingency allowance.

Combining the data supplied from the industries interviewed and the Board staff's own assessment of future trends resulted in special industrial requirements being forecast to rise from

87.8 billion cubic feet in 1966 to 222.2 billion cubic feet in 1995, with thirty-year requirements of some 4696 billion cubic feet.

Thirty-year requirements for 'other' industrial consumption, relating to fuel requirements for Alberta Gas Trunk Line and shrinkage at the Edmonton Liquid Gas and the Pacific Petroleums Ltd. Empress installations, totalled 598 billion cubic feet. Contingency allowances were assessed at 400 billion cubic feet for a general category and 1,000 billion cubic feet for iron ore processing requirements. The derivation of these amounts is discussed in detail under the Views of the Board heading.

Overall industrial requirements, being the total of the basic, special, 'other' and the contingency consumption categories, thus were estimated by the Board staff to increase from 120.1 billion cubic feet in 1966 to 345.9 billion cubic feet in 1995, with thirty-year requirements amounting to 7480 billion cubic feet.

In summary, the Board staff forecast the total domestic, commercial and industrial requirements to rise from 208.9 billion cubic feet in 1966 to 561.1 billion cubic feet by 1995. Thirty-year requirements were estimated to amount to some 11,912 billion cubic feet.

Views of the Board

1. Forecasting Method

The Board has considered the method employed by the Board staff of projecting the specific population served by gas as a

basis for forecasting domestic and commercial requirements. This procedure differs from the previous method used by the Board, which related growth of consumption in these categories to the growth in total Alberta population. It notes that the Board staff method essentially extends to the entire Province the method used by the Utility Companies for estimating requirements in their service areas. The Board believes this method possesses some merit over the total population method, in that it better accomodates the application of different rates of population growth, when appropriate, to the gas and non-gas served sectors of the population and the extension of service to new communities. Therefore, the method adopted by the Board staff of relating domestic and commercial consumption to the expected growth in the gas served population is endorsed by the Board.

2. Population

The Board has observed an increasing divergence between the previous forecast of Alberta population adopted by the Board and estimates of actual population, 1962 to 1965, inclusive. The Board population forecast exceeds the estimates of actual mid-year population published by the Dominion Bureau of Statistics and the Alberta Government for the years 1962, 1963, 1964 and 1965 by 3,000, 11,000, 28,000 and 55,000 respectively. The Board therefore recognizes that the trend revealed by these figures has necessitated a review of the forecast by the Board staff and agrees that some modification of the previous

projection is desirable in the early years, if not beyond. At this time, however, the Board is not prepared to approve the Board staff's revised forecast, or present an alternate forecast of its own. It believes that, in view of the fact that a new census will be taken in 1966 and the Board staff's decision to embark on a new population forecast when the results of the census are available, any comments it may have as to the appropriateness or otherwise of the Board staff's revised projection may be premature. Nevertheless, the Board considers that since the available evidence does indicate the previous population forecast is too high in the early years, the direction of the change made by the Board staff towards lower levels is reasonable.

The Utility Companies did not present a population forecast for the Province as a whole, but confined their projection to population consuming gas in their service areas. The Board has compared the Utility Companies' forecast to the corresponding figures presented by the Board staff, which showed the Board staff's projection of gas served population in the Utility Companies' service areas as significantly higher, to the extent of some 340,000 by 1995. Part of this difference relates to the inclusion in the Board staff numbers of new communities which may be served additional to those provided for by the Utility Companies, and of isolated consumers situated near gathering lines. However, the predominant portion reflects a higher growth rate assumed by the Board staff in urban areas.

The Utility Companies adopted a 2.5 per cent rate to apply from such time as their expected linear increases represented a rate of increase below this level for the Edmonton and Calgary metropolitan areas, and a corresponding figure of 2.0 per cent for the remaining Utility Companies service areas. The weighted average of the Utility Companies' estimated average growth rates from 1980 to 1995 is 2.4 per cent; the Board staff corresponding number is approximately 2.9 per cent.

The Board believes that the potential for future urban development may result in a somewhat higher population than expected by the Utility Companies. It is therefore not prepared to adopt figures as low as those suggested by them.

3. Domestic Requirements

Table C-1 and Figure C-1 show a comparison between the Board's 1964 forecast of domestic requirements, the Utility Companies' current projection and the Board staff's current forecast. The differences between the projections for the first half of the forecast period are slight. In 1981 the difference between highest (Board staff) and lowest (Utility Companies) estimate of annual gas consumption amounts to some 5.0 per cent. By 1995, the corresponding difference, with the highest represented by the Board 1964 prediction, is some 10.7 per cent. The variation in thirty-year requirements, using the lowest estimate (Utility Companies) as a base is 4.9 per cent for the Board staff prediction and 3.7 per cent for the Board 1964 forecast. The differences between thirty-

year totals therefore are not substantial. During the latter half of the forecast period the expected trends vary. The Board 1964 projection employs an exponential trend, while the patterns of growth assumed by the Board staff and by the Utility Companies are essentially linear. The relatively close agreement in aggregate between the forecasts masks some significant differences in detail. With respect to per capita rates of consumption, the Utility Companies anticipated constant levels for their service areas, the Board staff anticipated a slight decline over the forecast period, while conversely the Board 1964 projection postulated rising per capita consumption rates, the latter being expressed in terms of the total population of the Province. The difference between the Utility Companies and Board staff forecast, although mitigated somewhat by the variation in expected per capita consumption, is attributable primarily to the Board staff's higher estimate of the growth of the population served with gas, which, for the areas served by the Utility Companies, amounted to some 17 per cent by 1995. The Board 1964 projection was related to the growth in total population based on the previous population forecast, since modified by the Board staff. As previously mentioned in the discussion of population above, the Board considers the Utility Companies' population projection for their service areas may be low. While reserving specific judgment on several of the details, including per capita consumption rates and population, the

Board believes the Board staff's estimate of total domestic requirements to be reasonable and therefore accepts this forecast.

4. Commercial Requirements

Table C-2 and Figure C-2 show a comparison between the Board 1964, Utility Companies 1966 and current Board staff forecasts of commercial requirements. The Board observes that the differences between these projections are more significant than for the domestic estimates. The variation between the highest (Board staff) and lowest (Board 1964) annual anticipated requirements amounts to 28.6 per cent in 1981 and 28.5 per cent in 1995, both percentages relating to the lower figure. In terms of the thirty-year requirements, the Board staff's forecast and the Utility Companies' forecast are some 26.2 per cent and 18.4 per cent higher than the Board 1964 respective total. The latter forecast essentially assumed constant per capita commercial consumption of gas, with demand increasing in direct proportion to the anticipated rate of increase in the total population. The Utility Companies postulated increasing per capita rates to 1970, and constant rates thereafter. The Board staff's expected per capita rates increased significantly in the earlier forecast years, and then marginally from 1980 onwards, reaching constant levels by 1990. The differences in population projections previously discussed also contribute towards the variation in annual and total requirements.

The Board has examined its 1964 forecast both in relation to current data for 1964 and 1965 and anticipated trends in future years. The evidence indicates this forecast is likely to prove low. The Board therefore believes its 1964 projection should be replaced. In reviewing the Board staff's and Utility Companies' forecasts, the Board observed the staff's forecast exhibited a tendency to diverge increasingly from the Utility Companies' projection from 1973 to the end of the forecast period, a reflection in part of the difference between the staff's and Utility Companies' projection of population. The Board believes the staff's allowance for total growth in per capita consumption may be optimistic. All factors considered, the Board believes it appropriate to adopt a level of thirty-year requirements of 1925 billion cubic feet, approximately mid-way between the Utility Companies' total and the Board staff's total.

5. Industrial Gas Requirements

Table C-3 and Figure C-3 show a comparison between the Board 1964, Utility Companies 1966 and current Board staff forecasts of industrial requirements, the industrial requirements in each case being defined as basic and special requirements and contingency allowances.

Basic and Special. With respect to basic industrial requirements, the differences between the Board staff's and Utility Companies' forecasts are attributable in part to variations in classification and the Board staff's higher

forecast of industrial growth, particularly in the Medicine Hat area, and of population. The Board notes that the differences in terms of thirty-year requirements are not appreciable.

The Board observes the difference in method of forecasting industrial special requirements as between the Utility Companies and the Board staff, whereby the Utility Companies maintained the majority of their special loads at a constant level, and provided for increases not relating to firm plans in their contingency allowance. The Board believes the Board staff's method of forecasting special industrial demand, by including the impact on gas consumption of industry plans regarded as more than probable and also increasing loads where appropriate in relation to other measures of growth, offers some advantages over the Utility Companies' method by reducing the degree of arbitrary allocation inherent in the year by year phasing in of a large contingency allowance. The Board has reviewed the Board staff's forecast for the various components of the special industrial category, and regards the increases provided for as reasonable.

Overall, the Board accepts the staff's forecast of basic and special industrial consumption. It notes that the staff's forecast of basic and special industrial consumption is slightly higher than the Board's previous corresponding estimate reviewed in OGCB Report 64-11. The Board considers the increase desirable in view of the current level of interest

in industrial developments.

In view of the different manner by which special industrial consumption was projected by the Board and by the Utility Companies, a direct comparison of the two projections is not meaningful. A comparison of the subtotal of the basic and special industrial requirements and the general contingency allowance is presented below.

Contingency Allowances. The Board has treated the general contingency allowance separately from consideration of requirements for an iron ore processing scheme in the Peace River Area.

General. The Board believes it prudent, as in previous assessments of Alberta's thirty-year requirements, to provide for some industrial developments concerning which no definite decision has been taken at this time. The Board recognizes that the forecast of special industrial requirements contains, in aggregate, amounts which may possibly relate to a contingency allowance, given the possibility that one of the projects included in this category may not be consummated. The Board assesses a reasonable contingency allowance for the thirty-year period as 400 billion cubic feet, which is intended to cover several currently contemplated developments and two new industrial plants to be constructed in the future. The Board observes that this allowance is considerably less than the Utility Companies' contingency of 1,624 billion cubic feet. However, as mentioned previously, it believes that the

difference is primarily attributable to the methods employed by each in assessing the allowance. A direct comparison may be made using the combined totals of basic and special industrial consumption and general contingency allowance as forecast by the Utility Companies and the Board. The Board's estimate of this subtotal is some 5,882 billion cubic feet over the thirty-year period, while the corresponding figure for the Utility Companies is 5,692 billion cubic feet, only some 3.2 per cent lower.

Iron Ore Processing Requirements. The Board believes it proper to provide an allowance for the possible future establishment of a plant such as that proposed by Peace River Mining & Smelting Ltd. which would process iron ore deposits occurring in the Peace River area. Several factors are relevant in assessing potential plant requirements, including the nature of the process, the timing of plant construction, and the level of production. The amounts the Board has previously allowed for development of the Peace River ore deposits have been based, with respect to process, primarily on the original method of recovery proposed by Peace River Mining, and with respect to timing and production volume, on the Board's own estimates. The new process advanced by Peace River Mining has substantially expanded gas requirements per ton of production. Accordingly, a current assessment of requirements based on the new process is not directly related to previous estimates. With respect to timing, the Board believes that,

given the present stage of the pilot plant programme on the success of which the feasibility of Peace River Mining's scheme is predicated, the projected commencement of construction in early 1967 with completion by 1969 is optimistic. The Board therefore sets back the date for the inception of gas requirements for the scheme one year to 1970. With respect to amounts, the Board adopts a production schedule comprising the levels of production estimated by Peace River Mining to 1975, 600,000 tons per year from 1976 to 1985 and 1,000,000 tons per year from 1986 to 1995. The corresponding numbers for 1985 and 1995 as estimated by Peace River Mining amount to 1,500,000 and 2,500,000 tons respectively. Translating the Board production schedule into gas consumption results in total requirements over the period 1966 to 1995 of some one thousand billion cubic feet, less than one-half Peace River Mining's own estimate of requirements of some 2072 billion cubic feet adopted by the Utility Companies in their forecast. The Board recognizes that requirements will not necessarily develop in accordance with its assumed schedule, but believes the resulting allowance is proper at this time, having regard for the uncertainties relating to the current situation, the long term outlook and Peace River Mining's own market forecast.

The Board therefore expects requirements for the basic and special industrial categories and contingency allowances will increase from 102.0 billion cubic feet per year in 1966 to 332.6 billion cubic feet per year by 1995, with total

thirty-year requirements amounting to some 6882 billion cubic feet.

In addition to these categories of industrial consumption, the Board also estimates the amount of gas expected to be consumed by shrinkage at the Edmonton Liquid Gas and the Pacific Petroleums Empress processing plants, and of fuel requirements for Alberta Gas Trunk Line. The Utility Companies did not present a projection for this category. These requirements, designated 'other' industrial requirements, are expected to total some 598 billion cubic feet over the thirty-year period 1966 to 1995. This total is some 85 billion cubic feet less than the amount assessed by the Board in 1964. The difference is attributable primarily to the fact that the current estimate does not include any extension of requirements for the Empress plant following expiration of permits. If Trans-Canada's application should be approved, such requirements are anticipated to increase by 110 billion cubic feet.

Summary

Table C-4 and Figure C-4 show Alberta's total gas requirements as estimated by the Board in 1964 and by the Utility Companies and by the Board staff in 1966. The amounts shown in this table are inclusive of 'other' industrial requirements. For comparability, the Utility Companies' forecast has been amended by the addition of the Board's forecast of 'other' industrial requirements.

In terms of annual consumption, the Board now anticipates total requirements will increase from 209.2 billion cubic feet in 1966 to 555.6 billion cubic feet in 1995. These numbers exclude those amounts of 'other' industrial consumption contingent on approval of Trans-Canada's application. Requirements for the thirty-year period are expected by the Board to total some 11,850 billion cubic feet, again prior to consideration of the further amounts of 'other' industrial consumption referred to immediately above.

Table C-5 provides a summary of the Board 1964, Utility Companies 1966 and current Board staff and Board forecasts.

Permit Commitments

The present permit commitments, the volumes of gas removed to February 28, 1966 and the maximum daily authorized withdrawal rates, under authority of each of the 29 permits issued, are shown in Table C-6.

At February 28, 1966, permit volumes totalled some 21.6 trillion cubic feet of gas. At this date approximately 3.1 trillion cubic feet or 14 per cent had been removed.

TABLE C-1

FORECASTS OF ALBERTA DOMESTIC GAS REQUIREMENTS
(BILLIONS OF CUBIC FEET OF 1000 BTU GAS)

YEAR	BOARD 1964	UTILITY COMPANIES 1966	BOARD STAFF 1966
1966	50.8	50.7	50.0
1967	52.3	52.5	52.0
1968	53.9	54.2	53.9
1969	55.5	56.0	55.9
1970	57.2	57.8	58.1
1971	58.9	59.5	60.1
1972	60.7	61.3	62.2
1973	62.5	63.2	64.2
1974	64.4	65.0	66.1
1975	66.3	66.9	68.6
1976	68.3	68.6	70.7
1977	70.3	70.5	72.9
1978	72.4	72.4	74.9
1979	74.6	74.2	77.0
1980	76.8	76.0	79.5
1981	79.1	77.7	81.6
1982	81.5	79.5	83.8
1983	83.9	81.4	86.1
1984	86.4	83.4	88.3
1985	89.0	85.4	90.7
1986	91.7	87.3	93.1
1987	94.5	89.4	95.5
1988	97.3	91.7	98.0
1989	100.2	93.8	100.6
1990	103.2	96.2	103.2
1991	106.3	98.5	106.0
1992	109.5	100.7	108.7
1993	112.8	103.0	111.6
1994	116.2	105.5	114.5
1995	119.6	108.0	117.4
30-YEAR REQUIREMENTS	2,416	2,330	2,445
EQUIVALENT AVERAGE ANNUAL GROWTH RATE TO ACHIEVE TERMINAL YEAR (%)	3.0	2.6	3.0
EQUIVALENT AVERAGE ANNUAL GROWTH RATE TO ACHIEVE 30-YEAR TOTAL (%)	3.0	2.8	3.2

TABLE C-2

FORECASTS OF ALBERTA COMMERCIAL GAS REQUIREMENTS
(BILLIONS OF CUBIC FEET OF 1000 BTU GAS)

YEAR	BOARD 1964	UTILITY COMPANIES 1966	BOARD STAFF 1966
1966	34.1	39.3	38.8
1967	35.1	41.1	40.5
1968	36.1	43.1	42.0
1969	37.1	44.7	43.7
1970	38.1	46.2	45.6
1971	39.2	47.7	47.3
1972	40.3	49.2	49.0
1973	41.4	50.6	50.9
1974	42.6	52.0	52.5
1975	43.8	53.5	54.6
1976	45.0	55.0	56.6
1977	46.3	56.3	58.6
1978	47.6	57.8	60.6
1979	48.9	59.3	62.5
1980	50.3	60.7	64.6
1981	51.7	62.2	66.5
1982	53.1	63.7	68.4
1983	54.6	65.2	70.3
1984	56.1	66.7	72.3
1985	57.7	68.4	74.3
1986	59.3	70.1	76.4
1987	61.0	71.7	78.5
1988	62.7	73.5	80.7
1989	64.5	75.2	83.0
1990	66.3	76.9	85.3
1991	68.2	78.8	87.7
1992	70.1	80.7	90.1
1993	72.1	82.8	92.6
1994	74.1	84.8	95.2
1995	76.1	86.8	97.8
30-YEAR REQUIREMENTS	1,574	1,864	1,987
EQUIVALENT AVERAGE ANNUAL GROWTH RATE TO ACHIEVE TERMINAL YEAR (%)	2.8	2.8	3.2
EQUIVALENT AVERAGE ANNUAL GROWTH RATE TO ACHIEVE 30-YEAR TOTAL (%)	2.8	3.0	3.4

TABLE C-3

FORECASTS OF ALBERTA INDUSTRIAL GAS REQUIREMENTS*
(BILLIONS OF CUBIC FEET OF 1000 BTU GAS)

YEAR	BOARD 1964	UTILITY COMPANIES 1966	BOARD STAFF 1966
1966	97.9	99.1	102.0
1967	101.9	104.9	107.4
1968	119.1	109.5	109.3
1969	123.4	121.0	123.8
1970	127.9	133.3	141.2
1971	132.6	138.9	162.6
1972	151.5	155.4	185.7
1973	155.6	163.2	191.4
1974	160.9	180.5	206.3
1975	166.4	187.3	200.8
1976	172.1	201.1	206.4
1977	178.0	208.9	212.1
1978	184.2	237.2	216.8
1979	190.6	270.7	221.4
1980	197.3	276.2	228.9
1981	204.2	281.6	234.5
1982	224.4	286.8	236.5
1983	231.9	291.9	241.5
1984	239.7	297.4	247.4
1985	247.8	303.4	252.5
1986	256.2	308.1	279.6
1987	265.0	313.2	285.0
1988	274.1	318.6	290.8
1989	283.6	381.1	296.2
1990	293.5	386.4	302.2
1991	303.8	390.7	307.6
1992	314.5	396.3	313.6
1993	325.6	401.4	319.9
1994	336.9	406.8	326.1
1995	348.4	412.3	332.6
30-YEAR REQUIREMENTS	6,409	7,763	6,882
EQUIVALENT AVERAGE ANNUAL GROWTH RATE TO ACHIEVE TERMINAL YEAR (%)	4.5	5.0	4.2
EQUIVALENT AVERAGE ANNUAL GROWTH RATE TO ACHIEVE 30-YEAR TOTAL (%)	4.9	6.0	5.1

* INCLUDES CONTINGENCY AND IRON ORE PROCESSING REQUIREMENTS BUT EXCLUDES 'OTHER' INDUSTRIAL REQUIREMENTS.

TABLE C-4

FORECASTS OF ALBERTA TOTAL GAS REQUIREMENTS*
(BILLIONS OF CUBIC FEET OF 1000 BTU GAS)

YEAR	BOARD 1964	UTILITY COMPANIES 1966	BOARD STAFF 1966
1966	201.2	207.2	208.9
1967	209.1	218.8	220.2
1968	230.2	230.9	229.3
1969	239.1	245.8	247.5
1970	246.3	261.9	269.5
1971	253.8	270.7	294.6
1972	275.6	290.5	321.5
1973	282.6	301.6	331.1
1974	291.0	322.1	349.5
1975	299.6	332.8	349.1
1976	308.5	349.8	358.8
1977	317.7	360.8	368.7
1978	327.3	392.5	377.4
1979	337.2	429.3	386.0
1980	347.5	438.5	398.6
1981	358.1	446.0	407.1
1982	382.1	452.6	411.2
1983	393.5	458.7	418.1
1984	405.3	466.2	426.7
1985	417.6	474.5	434.8
1986	430.3	481.3	464.9
1987	443.6	488.6	473.3
1988	457.2	497.5	483.2
1989	471.4	563.1	492.8
1990	486.1	571.8	503.0
1991	501.4	580.3	513.6
1992	517.2	590.0	524.7
1993	533.6	600.5	537.4
1994	550.3	610.3	549.1
1995	567.2	620.4	561.1
30-YEAR REQUIREMENTS	11,082	12,555	11,912
EQUIVALENT AVERAGE ANNUAL GROWTH RATE TO ACHIEVE TERMINAL YEAR (%)	3.6	3.9	3.5
EQUIVALENT AVERAGE ANNUAL GROWTH RATE TO ACHIEVE 30-YEAR TOTAL (%)	3.9	4.5	4.1

* INCLUDES 'OTHER' INDUSTRIAL REQUIREMENTS (SHRINKAGE AT EMPRESS AND EDMONTON LIQUID GAS PLANTS AND ALBERTA GAS TRUNK LINE FUEL). UTILITY COMPANIES' NUMBERS ADJUSTED TO INCLUDE BOARD ESTIMATE OF 'OTHER' INDUSTRIAL.
IF THE REQUESTED INCREASE IN PERMIT VOLUMES OF GAS IS GRANTED, 'OTHER' INDUSTRIAL REQUIREMENTS WILL BE INCREASED BY 110 BILLION CUBIC FEET FOR THE 30-YEAR PERIOD.

TABLE C-5

SUMMARY OF FORECASTS OF ALBERTA GAS REQUIREMENTS
(BILLIONS OF CUBIC FEET OF 1000 BTU GAS)

	BOARD 1964	UTILITY COMPANIES 1966*	BOARD STAFF 1966	BOARD 1966
DOMESTIC				
1966 ANNUAL	50.8	50.7	50.0	50.0
1995 ANNUAL	119.6	108.0	117.4	117.4
30-YEAR TOTAL	2,416	2,330	2,445	2,445
COMMERCIAL				
1966 ANNUAL	34.1	39.3	38.8	39.1
1995 ANNUAL	76.1	86.8	97.8	92.3
30-YEAR TOTAL	1,574	1,864	1,987	1,925
INDUSTRIAL **				
1966 ANNUAL	116.3	117.2	120.1	120.1
1995 ANNUAL	371.5	425.6	345.9	345.9
30-YEAR TOTAL	7,092	8,361	7,480	7,480
TOTAL				
1966 ANNUAL	201.2	207.2	208.9	209.2
1995 ANNUAL	567.2	620.4	561.1	555.6
30-YEAR TOTAL	11,082	12,555	11,912	11,850
EQUIVALENT AVERAGE ANNUAL GROWTH RATE TO ACHIEVE TERMINAL YEAR (%)	3.6	3.9	3.5	3.4
EQUIVALENT AVERAGE ANNUAL GROWTH RATE TO ACHIEVE 30-YEAR TOTAL (%)	3.9	4.5	4.1	4.1

* INDUSTRIAL AND TOTAL NUMBERS ADJUSTED TO INCLUDE BOARD 'OTHER' INDUSTRIAL CONSUMPTION.

** IF THE REQUESTED INCREASE IN PERMIT VOLUMES OF GAS IS GRANTED, 'OTHER' INDUSTRIAL REQUIREMENTS WILL BE INCREASED BY 110 BILLION CUBIC FEET FOR THE 30-YEAR PERIOD.

TABLE C-6

PERMIT COMMITMENTS

(ALL VOLUMES AT 14.65 PSIA AND 60°F)

PERMIT NUMBER	PERMITTEE	FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWN TO FEBRUARY 28, 1966 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
AS 64-3	Alberta and Southern Gas Co. Ltd.	Berland River, Bigstone, Brazeau River, Burnt Timber, Caroline, Carson Creek, Carson Creek North, Crossfield (Rundle Pool), Ferrier (Viking A and Cardium B Pools), Fox Creek, Fox Creek North, Fox Creek West, Harmattan-Elkton (D-3A Pool), Homeglen-Rimbey, Hunter Valley, Kaybob, Leafland North, Marlboro, Minnehik-Buck Lake, Pembina (Lobstick Glauconitic and Lobstick Ostracod Pools), Pine Creek, Pine North-west, Sundre, Sylvan Lake, Waterton, Westerose, Westerose South, Westward Ho, Wildcat Hills, Wildhorse Creek, Willesden Green, Wilson Creek, and Windfall.	750.0	250.0	6450.0	632.1	5817.9
BH 61-1 BS 61-1 CS 61-1 COG 61-1 SEL 61-1 JMW 61-1 CEL 61-1	Delta Gas & Transmission Ltd. Bailey Selburn Oil and Gas Ltd. The California Standard Company Charter Oil and Gas Ltd. Selbay Exploration Ltd. J. Merril Wright, Jr. Crowfoot Exploration Ltd.	Medicine Hat	9.5	3.5	71.0	-	71.0
CD 63-1	Canadian Delhi Oil Ltd.	Medicine Hat	4.3	1.57	32.3	1.9	30.4
CM 54-1 and CM 61-2	Canadian-Montana Pipe Line Company	Aden, Black Butte, Comrey, Manyberries, Pakowki Lake, Pendant d'Oreille, and Smith Coulee	100.0	20.0	391(1)	190.8	200.2
CP 63-1	Canadian Pacific Oil and Gas Limited	Medicine Hat	0.1	0.0365	0.750	0.06	0.690

(1) Total initial marketable gas in the fields shown.

(CONTINUED)

TABLE C-6 (CONTINUED)

PERMIT NUMBER	PERMITTEE	FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWN TO FEBRUARY 28, 1966 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
CMM 61-1 MOG 61-1 ROC 61-1	J. Ray McDermott & Co. Inc. Mayfair Oil & Gas (1961) Ltd. Richfield Oil Corporation	Medicine Hat	8.3	3.0	62.0	4.3	57.7
ROC 65-2	Richfield Oil Corporation	Medicine Hat	0.26	0.088	2.0	0.02	1.98
HB 63-1	Hudson's Bay Oil and Gas Company Limited	Medicine Hat	1.02	0.372	7.65	0.24	7.41
SPC 57-1	Many Islands Pipe Lines Ltd.	Medicine Hat	135.5	44.5	609.4	105.7	508.7
MO 66-1	Murphy Oil Company Ltd.	Red Coulee	0.6	-	0.5	-	0.5
NSU 64-1	The British American Oil Company Limited, Royalite Oil Company, Limited, Sun Oil Company and United Canso Oil & Gas Ltd.	Antelope and Esther	11.4	4.2	40.0	3.4	36.6
	Peace River Transmission Company Limited	Pouce Coupe	6.0	0.60	18.0	12.3	20.4
	Peace River Transmission Company Limited	Pouce Coupe South	6.9	0.98	19.7		
B 64-1	Patrick T. Buckley	Vanalta No. 4 Well	1.3 MMcf Per Mo.	0.010	-	0.06	-
PG 64-1	Provo Gas Producers Limited	Halliday, Richdale and Wildunn Creek	10.0	3.6	45.0	2.4	42.6
TC 64-6	Trans-Canada Pipe Lines Limited	Atlee-Buffalo, Bindloss, Carstairs, Cessford, Chigwell, Connorsville, Countess, Crossfield, (Cardium Pool), Crossfield East, Edson, Enchant, Erskine, Fenn-Big Valley, Fenn West, Gilby, Hackett, Hamilton Lake, Harmattan-Elkton (Rundle A Pool), Homeglen-Rimbey, Hussar, Innisfail, Kessler, Lone Pine Creek, Medicine River, Medicine Hat, Minnehik-Buck Lake, Nevis, Olds, Oyen, Pincher Creek, Prevo, Princess, Provost,	1550.0	525.0	12080.0	1765.5	10314.5

(CONTINUED)

TABLE C-6 (CONTINUED)

PERMIT NUMBER	PERMITTEE	FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWN TO FEBRUARY 28, 1966 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
TC 64-6 (CONT'D)	TRANS-CANADA PIPE LINES LIMITED	RETLAW, RICH, SEDALIA, SIBBALD, STANDARD, STETTLER, SYLVAN LAKE, THREE HILLS CREEK, VERGER, WAYNE-ROSEDALE, WESTEROSE SOUTH, WIMBORNE AND WOOD RIVER.					
WC 52-1	WESTCOAST TRANSMISSION COMPANY LIMITED	BRAEBURN, BURNT RIVER, GORDONDALE, POUCE COUPE, POUCE COUPE SOUTH AND SADDLE HILLS.	125.0	35.0	463.0	185.2	277.8
WC 59-3	WESTCOAST TRANSMISSION COMPANY LIMITED	CROSSFIELD (CROSSFIELD CALGARY BASAL QUARTZ, RUNDLE, AND WABAMUN POOLS), AND SAVANNA CREEK.	162.2	53.1	1081.2	174.0	907.2
WC 61-4	WESTCOAST TRANSMISSION COMPANY LIMITED	BOUNDARY LAKE SOUTH	VOLUMES NOT TO EXCEED THOSE AUTHORIZED IN PERMIT NO. WC 52-1.				
WC 62-5	WESTCOAST TRANSMISSION COMPANY LIMITED	WORSLEY	58.3	16.0	220.0	45.9	174.1
			2788.38	961.5565	21588.5	8123.88	18464.68

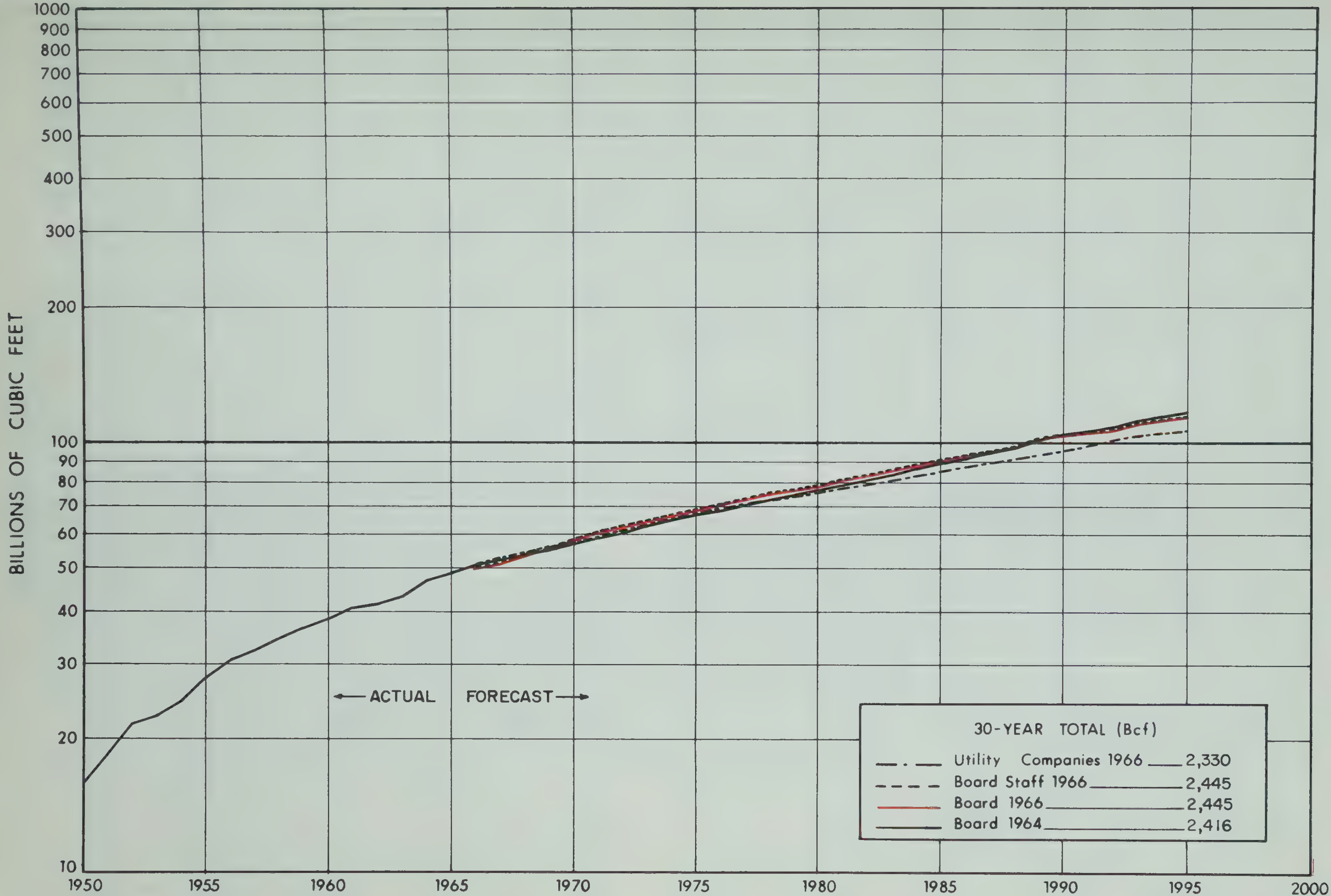

FIGURE C-1 — COMPARISION OF FORECASTS OF ALBERTA DOMESTIC GAS REQUIREMENTS

OIL AND GAS CONSERVATION BOARD
CALGARY, ALBERTA

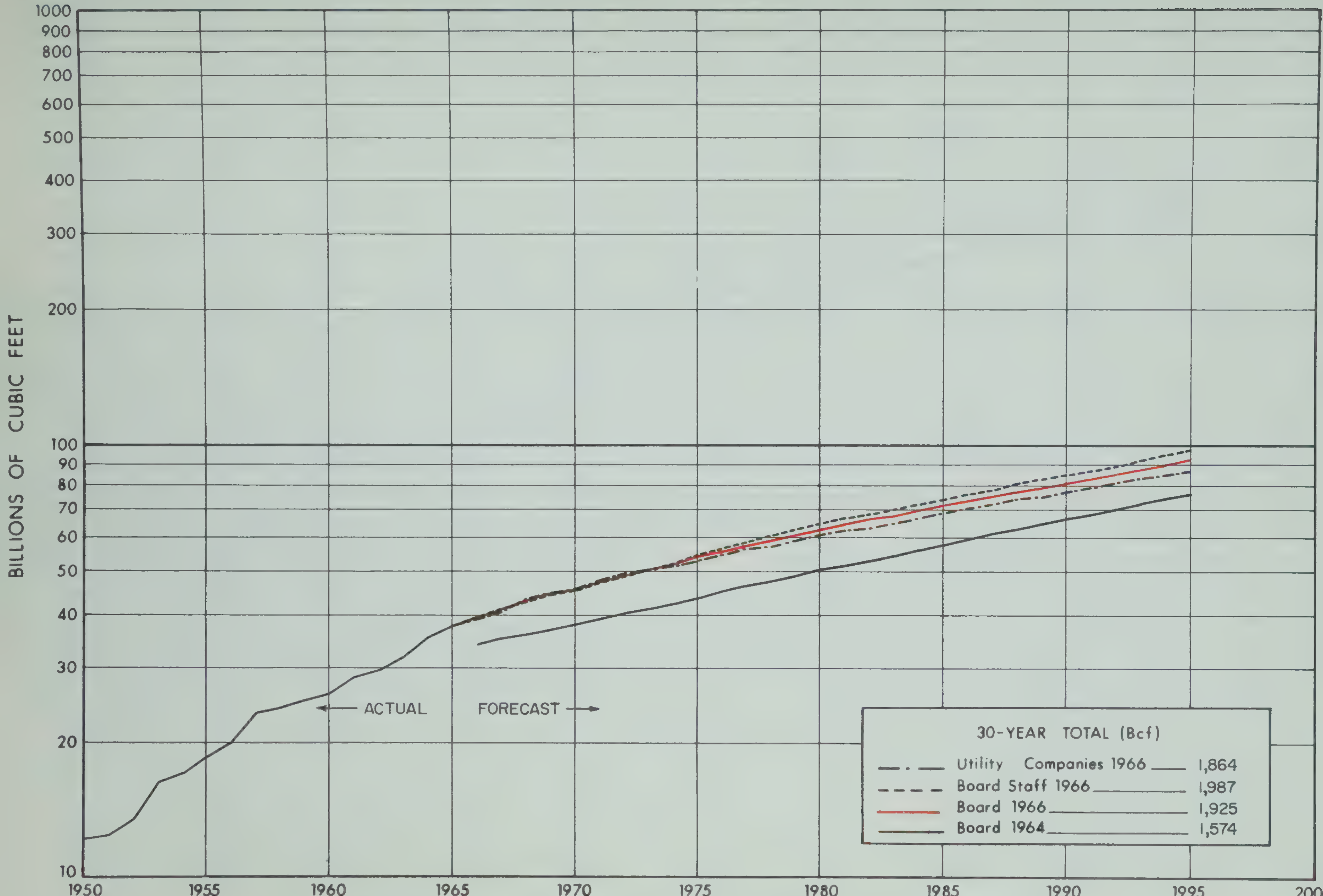

FIGURE C-2 — COMPARISION OF FORECASTS OF ALBERTA COMMERCIAL GAS REQUIREMENTS

OIL AND GAS CONSERVATION BOARD
CALGARY, ALBERTA

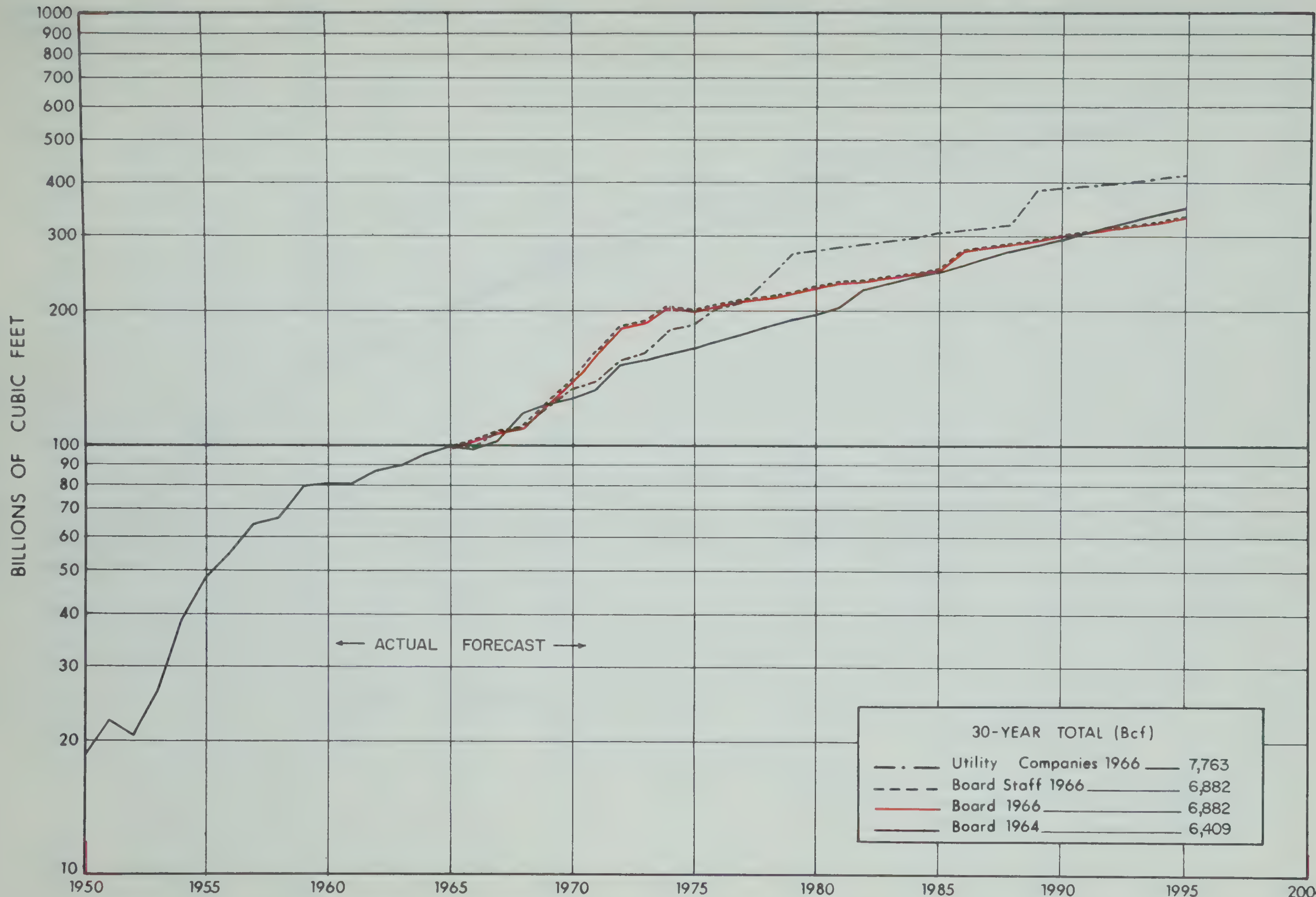

FIGURE C-3 — COMPARISION OF FORECASTS OF ALBERTA INDUSTRIAL GAS REQUIREMENTS

OIL AND GAS CONSERVATION BOARD
CALGARY, ALBERTA

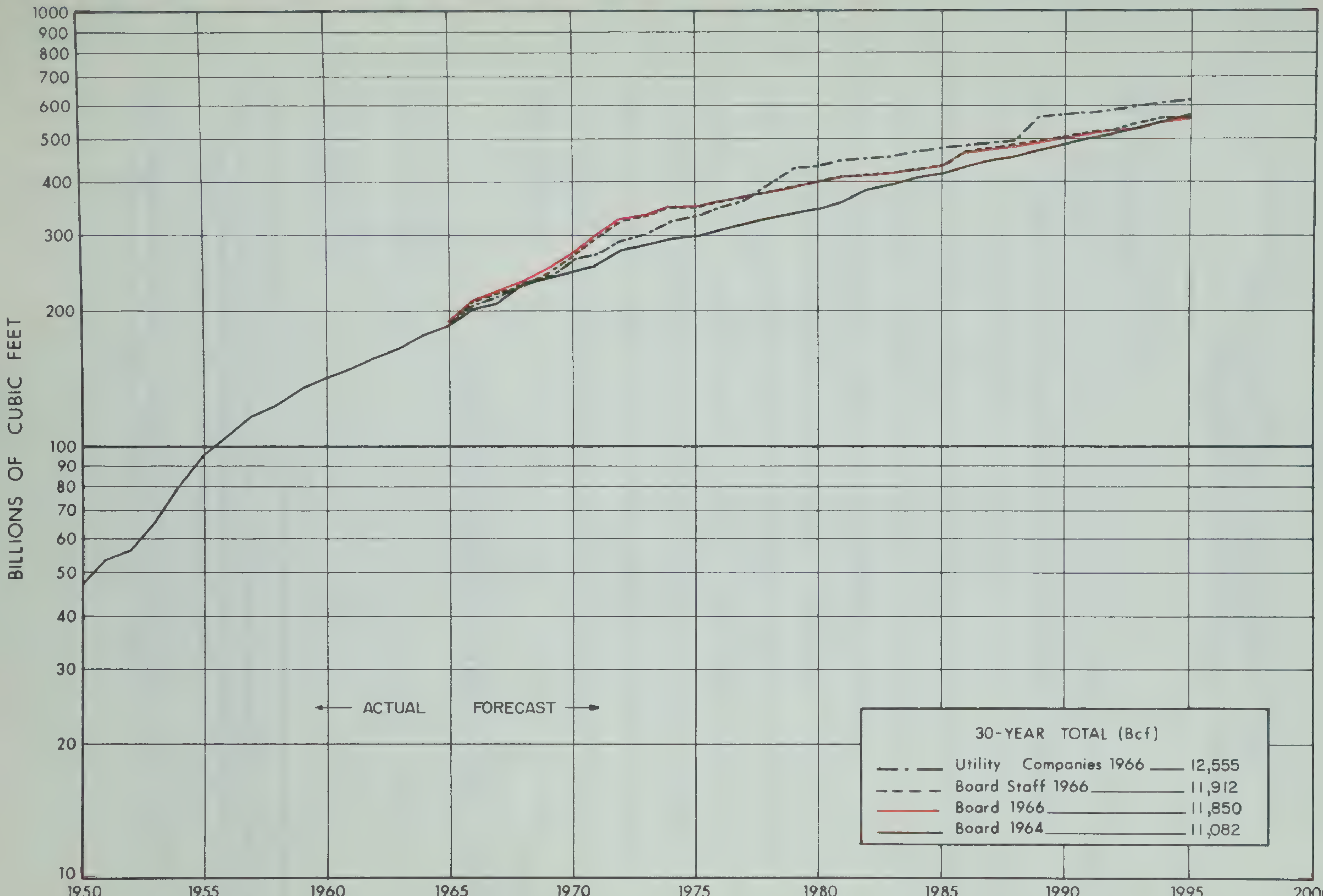

FIGURE C-4 — COMPARISION OF FORECASTS OF ALBERTA TOTAL GAS REQUIREMENTS

OIL AND GAS CONSERVATION BOARD
CALGARY, ALBERTA

APPENDIX D

THE MEETING OF ALBERTA'S REQUIREMENTS FOR GAS AND THE PRESENT PERMIT COMMITMENTS, AND THE RESULTING SURPLUS

Views of the Applicant and Interveners

Neither Trans-Canada nor any of the interveners at the hearing presented detailed evidence to show how Alberta's thirty-year requirements for gas might be met. However, Trans-Canada did estimate the surplus of gas in the Province employing the method currently in use by the Board and a new method which it proposed for the Board's consideration.

In calculating the surplus as of February 28, 1966, Trans-Canada updated reserve and requirement figures published by the Board in its OGCB Report 64-11[1] and OGCB Report 65-8[2]. The following table and discussion summarizes the changes made by Trans-Canada and the basis on which they were made. (All volumes are in trillions of cubic feet at 1000 Btu per cubic foot).

	Board Estimate (June 30/64)(December 31/64)	Difference	Trans-Canada Estimate (Feb.28,1966)
Reserves Within Economic Reach	33.6	+3.8	37.4
Reserves Beyond Economic Reach	3.8	-0.6	3.2

(1) Report on the Applications of Trans-Canada Pipe Lines Limited and Alberta and Southern Gas Co. Ltd. under The Gas Resources Preservation Act, 1956. November, 1964.

(2) Reserves of Gas, Natural Gas Liquids, Crude Oil and Sulphur, Province of Alberta. December 31, 1964.

	Board Estimate (June 30/64)	Board Estimate (December 31/64)	Difference	Trans-Canada Estimate (Feb.28,1966)
Deferred Reserves	5.0		-0.1	4.9
Deferred Reserves Available Within Thirty Years	4.5		-0.1	4.4
Two Years Growth of Reserves	5.0		+0.2	5.2
Alberta Requirements for Delivery	10.5		+0.7	11.2
Alberta Requirements to meet Thirtieth Year Peak Day	5.8		+0.4	6.2
Required to Meet Permit Commitments	20.6		-1.1	19.5
Required to Meet Permit Terminal Year Peak Days	2.6		-1.4	1.2

The Trans-Canada estimate of reserves within economic reach results from an adjustment to the reserves as estimated by the Board at December 31, 1964. The adjustment reflects Trans-Canada's estimate of reserves for eight fields included in Permit No. TC 64-6 of which the Trans-Canada estimate is significantly higher than the Board's, for twenty-six new fields or areas from which Trans-Canada wishes to remove gas, and for three other fields where significant developments have taken place during 1965. The reserves have also been adjusted to reflect production during the period December 31, 1964 to February 28, 1966. Trans-Canada's estimate of reserves beyond economic reach

results from an adjustment to the Board's estimate as of December 31, 1964, based on a review of the fields or areas categorized by the Board as beyond economic reach as of that date. Trans-Canada's review resulted in the subtraction from this category of the reserves in some eleven fields or areas which the Board previously classified as beyond economic reach but which are now under contract, and the reserves in three other fields or areas which have appreciated sufficiently that Trans-Canada now considers them within economic reach. Also, two other fields considered beyond economic reach have experienced sizeable reserve growth over the past year. This growth has been added by Trans-Canada to the Board's total as of December 31, 1964. Trans-Canada estimated the deferred reserves by summing the reserves set by the Board as of December 31, 1964 for ten fields from which Trans-Canada believes production will be deferred and by accepting the Board's estimate included in OGCB Report 64-11 that 0.5 trillion cubic feet of gas production will be deferred beyond a thirty-year period. The 5.2 trillion cubic feet associated with two years growth of gas reserves as used by Trans-Canada reflects its estimate of the long-term growth rate of initial marketable gas reserves. The growth rate was based on Trans-Canada's estimate of initial marketable reserves as of February 28, 1966 and the Board's estimate of initial marketable reserves as of June 30, 1955.

The Trans-Canada estimate of Alberta's thirty-year

requirements is the Board's estimate as of June 30, 1964 extended for two additional years at the same rate of growth. The reserves needed to meet these additional requirements have been calculated using the formula approach and the factors used in the formula by the Board in its OGCB Report 64-11. The Trans-Canada estimate of the remaining permit commitments is the Board's statement as of June 30, 1964 adjusted for the 1.1 trillion cubic feet of gas removed under the permits during the period July 1, 1964 to February 28, 1966. Trans-Canada's allowance of reserves to meet the permit terminal year peak days reflects some five per cent of the initial permit commitments.

The Trans-Canada analysis using the method of calculating the surplus previously used by the Board, results in an estimated surplus as of February 28, 1966 of about 4.2 trillion cubic feet before the release of the reserves required to protect for permit peak days and some 6.8 trillion cubic feet after the release of this peaking gas.

The method of calculating the surplus proposed by Trans-Canada segregates the reserves and requirements into "contractable" and "remaining future" components. As discussed in Section V of this report Trans-Canada suggested that the contractable reserves be taken as the reserves now considered within economic reach less those reserves which are deferred. It further suggested that the contractable Alberta requirements reflect the amount of gas remaining in those fields currently supplying

Alberta's requirements plus an allowance to meet the anticipated growth in Alberta's requirements for a few years into the future, and that the permit requirements be taken as 105 per cent of the original permit quantities less production to date. The 105 per cent was selected as Trans-Canada's estimate of reserves needed under contract in order to produce the quantities approved for removal from the Province during the term of the permits. Trans-Canada suggested where the contractable reserves are found to exceed the contractable Alberta requirements plus the reserves required to meet the permit commitments, that this quantity could be termed a contractable surplus. The contractable surplus could then be declared surplus to the Provincial needs if the Board is satisfied that the remaining future requirements of the Province could be met from deferred reserves, reserves currently beyond economic reach, appreciation of established reserves and from reserves yet to be discovered.

The Trans-Canada analysis, using its proposed method of calculating the surplus, results in an estimated contractable surplus as of February 28, 1966 of about 5.4 trillion cubic feet. The analysis also shows remaining future requirements of some 6.6 trillion cubic feet. Trans-Canada contended in its submission that the appreciation of presently established reserves, the portion of the reserves now considered beyond economic reach which would become within economic reach during the thirty-year period, and the substantial quantity of reserves that will be discovered in the future will be more than adequate

to supply these remaining future requirements. Trans-Canada suggested that for this reason the Board can safely declare the contractable surplus of 5.4 trillion cubic feet surplus to Alberta's requirements, and further stated that the Board could do so even though future requirements were much greater than those now indicated.

The Utility Companies in their submission presented an example surplus calculation adopting the general principle of the method proposed by Trans-Canada but incorporating certain modifications of that method. The surplus was calculated as of December 31, 1965, and the figures used in the example calculation were taken from the original Trans-Canada application before its amendment at the hearing to reflect data up to February 28, 1966. Since the figures used in the calculation were not the Utility Companies' own estimates and since they were subsequently amended by Trans-Canada, the Board has not reproduced them in this Appendix.

The major alterations suggested by the Utility Companies to the Trans-Canada proposed method were as follows:

1. The contractable Alberta requirements should be taken as the greater of thirty times the requirements of the first year of the period under consideration or the remaining reserves in those fields connected to and supplying Alberta's requirements. (Trans-Canada had suggested the remaining reserves in fields connected to Alberta's requirements plus some allowance for future contracting.)

2. Since in the view of the Utility Companies any excess of gas reserves in fields included in a permit over those quantities set out in the permit are not actually available for local requirements, the allowance for permit requirements should be taken as the grand total of the remaining reserves in the permit fields. (Trans-Canada had suggested an allowance of some 105 per cent of the actual commitment.)

3. The Board should maintain its existing policy of using only two year's growth of gas reserves and some definite fraction of reserves now considered beyond economic reach in appraising the future surplus. (Trans-Canada had proposed that the Board review the remaining requirements in the light of the situation at the time of the review and had suggested that the Board could place greater reliance on future discoveries than it is now doing.)

The City of Edmonton and Alberta and Southern, in their submissions, supported the general principles of the Trans-Canada proposed method for calculating the surplus but did not include evidence respecting the actual figures to be used in the calculation.

Views of the Board

As discussed in Section V of this report, the Board has decided to accept the principle of categorizing suggested by Trans-Canada and endorsed by the interveners at the hearing, and has formulated a modified method for determining the gas surplus to Alberta's requirements and the existing permit

commitments. In the modified method, the Board will include as contractable reserves, the established gas reserves currently considered within economic reach less those reserves from which production will be deferred. The total Alberta requirements (the total gas needed to meet the thirty-year Alberta requirements including the thirtieth year peak) will be calculated as in the past using a combination of deliverability schedules and the formula method. As suggested by the Utility Companies the contractable Alberta requirements will be taken as the greater of thirty times the requirements of the first year of the period under consideration or the remaining reserves in those fields connected to and supplying Alberta's requirements. The permit requirements will be taken as the remaining permit commitments plus that quantity of gas necessary to provide for the terminal year peak day for only those permits where previous calculations published by the Board have allowed for such cushion gas. The Board will take as the remaining requirements the total gas needed to meet Alberta's thirty-year requirements less those requirements classified as contractable. The remaining and future reserves will be taken as the growth in gas reserves anticipated over a two-year period, that portion of the reserves now beyond economic reach which the Board believes will be available within the thirty-year period and those deferred reserves which the Board believes will be produced within thirty years. If the remaining requirements should exceed the remaining and future

reserves, the Board will have regard for the fact that the cushion gas portion of the remaining requirements is less definite than the portion which must be delivered and may utilize some additional growth of gas reserves (beyond that expected in two years) to overcome the deficit. The circumstances under which this might be done are discussed in Section V.

1. The Meeting of Alberta's Long Term Requirements (January 1, 1966 - December 31, 1995)

As discussed in Appendix C, the thirty-year gas requirements of the Province have been estimated at some 11,900 billion cubic feet with a thirtieth year peak day of some 2,600 million cubic feet. The fields now connected to and supplying Alberta's requirements are listed in Table D-1. The table also gives the Board's current estimate of the remaining reserves of marketable gas and the reserve-delivery ratio of each of the fields.

Illustrative deliverability schedules (not reproduced here) prepared by the Board indicate that of the total of some 6,580 billion cubic feet of gas shown in Table D-1 some 4,900 billion cubic feet will be produced during the thirty-year period and the remaining unproduced reserve will be capable of sustaining a peak day delivery of some 500 million cubic feet in the thirtieth year. This means that total deliveries of about 7,000 billion cubic feet (11,900 - 4,900 = 7,000) and a thirtieth year peak delivery of about 2,100 million cubic feet

per day (2,600 - 500 = 2,100) will be required from other sources. The actual quantities of gas necessary to provide these deliveries may be calculated using the formula method presented in Appendix E of OGCB Report 64-11. With respect to the factors to be used in the formula, the Board believes that since this gas must come in part from established gas reserves not now connected to local utilities nor authorized for removal from the Province, and in part from gas reserves not yet developed, the factors should reflect the delivery characteristics of both of these sources of gas. In order to accomplish this, the Board has decided to use the average reserve-deliverability ratio for all of the currently established reserves in the Province. Table D-2 presents the results of the Board's review of the average ratio and confirms the continued use of a ratio of 2.4. A similar study indicates that a reservoir recovery factor of 0.84 is the current average and is appropriate to use in protecting for the additional Alberta requirements. The total marketable gas needed to meet Alberta's thirty-year requirements as calculated by the formula method is:

From now connected sources for actual delivery	4,900
From additional sources for actual delivery	7,000
From now connected sources to protect thirtieth year peak(1)	1,680

From additional sources to protect thirtieth year peak[2]	4,380		
Total	17,960	say	18,000

(1) i.e. 6,580 - 4,900 = 1,680

(2) Determined as $R_p = 1.3\ FP_n - (1 - K)\ (1.3\ FP_n + A_1S)$

$$= 1.3\ (2.4)\ (2{,}100) - (1 - 0.84)\left[1.3\ (2.4)\ (2{,}100) + 7{,}000\right]$$

$= 6{,}552 - 2{,}168 = 4{,}384$; say 4,380 billion cubic feet.

The requirements protected for in the above analysis include pipe line fuel for the Trunk Line system and the shrinkage anticipated at the Empress plant for those quantities of gas heretofore approved for removal from the Province. Should the removal of the additional quantities requested by Trans-Canada be approved, this fuel and shrinkage would be increased and the gas needed to meet Alberta's thirty-year requirements would increase by about 0.1 trillion cubic feet to a total of some 18.1 trillion cubic feet.

2. The Remaining Permit Commitments

The permit commitments remaining at February 28, 1966 have been shown in Appendix C to be some 18,460 billion cubic feet with a maximum peak day of about 2,790 million cubic feet.

The fields included in each of the existing permits are shown in Table D-3. The table also shows the Board's current estimate of the remaining reserves of marketable gas and the ratio of marketable gas in place to delivery capacity for each field. The table reflects changes in the remaining

marketable reserves which have occurred since the preparation of OGCB Report 64-11, and also where major changes have occurred, it reflects a re-analysis of the reserve-delivery ratios.

The results of the Board analysis with respect to the meeting of the remaining permit commitments are shown in Table D-4. Columns 1 and 2 show respectively the remaining permit commitment and the maximum day authorized in each of the permits. These figures were obtained from Appendix C and have been converted to the basis of 1000 Btu per cubic foot. The expiry date of each of the permits is shown in Column 3. Columns 4 and 5 present the Board's current estimate of the remaining marketable reserves and the reserve-delivery ratio (both obtained from Table D-3) of the fields included in each permit. Column 6 shows the composite correction factor for each of the permittees' systems as determined from the illustrative deliverability schedules prepared prior to the release of the Board's OGCB Report 64-11. (The Board does not believe that sufficient changes have occurred in the fields supplying each of the permits to warrant a detailed restudy and redetermination of the composite correction factor.) The estimated quantity of marketable gas in place required to meet the peak day commitment in the terminal year of each permit is shown in Column 7. Column 8 shows the marketable gas equivalent of Column 7. These values were obtained by deducting from Column 7 the marketable gas equivalent of the

gas that will remain in the reservoirs at abandonment. The total amount of marketable gas required to meet the permit requirements, both deliveries and peak day, is shown in Column 9. Columns 10 and 11 present the Board's estimate of the amount of marketable gas in the fields in the permits, excess to the permit commitments before and after the expiry date of each permit.

In the case of the Alberta and Southern permit, three entries have been made. The first line gives the total remaining permit commitment and the quantity of gas which would be required to sustain the maximum day to the terminal year of the permit. The second line gives the quantity of gas which the Board anticipates could be delivered while sustaining the maximum daily rate specified in the permit. The third line shows the remainder of the permit commitment, which the Board believes could be produced prior to the terminal date of the permit although not necessarily at the approved maximum daily rate.

In the case of permits where all of the reserves in the permit fields have been granted to the permittee or where no allowance for maximum day protection has been made by the Board, columns 5 through 8 which support the calculation of marketable reserves required to meet the terminal year peak day, have not been completed.

In the the case of the Westcoast Transmission Co. Ltd. Peace River permit, the remaining commitment has been reduced

to reflect the delivery of gas from the Worsley Field to meet future requirements of an iron ore processing industry in the Peace River area. Under the terms of Permit No. WC 62-5 the amount of gas remaining in the Worsley Field at the time of the inception of an iron ore processing industry in the Peace River region would be available to contribute towards the requirements of such an industry. As is discussed in Appendix C, the Board believes that an iron ore processing industry would probably not commence operations in the Peace River region before the year 1970. Hence, for the purpose of the table, the permit commitment has been reduced by the Board's estimate of the volume of gas (amounting to some 150 billion cubic feet on a 1000 Btu per cubic foot basis), which the permittees would be required to make available if the iron ore processing industry begins operations in 1970.

Table D-4 shows that a total marketable gas reserve of some 21,300 billion cubic feet is required to meet the commitment of all existing permits of about 19,400 billion cubic feet with a maximum peak of some 2,900 million cubic feet per day. Since reserves of almost 22,200 billion cubic feet are available, a surplus of some 900 billion cubic feet of gas exists in the fields included in the present permits. However, after the expiry dates of the permits, several years before the end of the thirty-year period, an additional 1,900 billion cubic feet, the amount allowed to meet the terminal year peak day deliveries, will become excess to the

existing permit commitments.

3. The Gas Surplus to Alberta's Requirements and the Existing Permit Commitments

Although the Board has adopted a modified method for calculating the gas surplus to Alberta's requirements and the existing permit commitments, for purposes of comparison it has been decided to include in this report the surplus calculation using the previous method as well as the modified method.

The surplus calculation using the previous Board method is presented in Table D-5. The table shows that the reserves within economic reach (37.2 trillion cubic feet) plus three-quarters of those reserves beyond economic reach (2.3 trillion cubic feet) less that portion of oil field gas which the Board believes will be deferred beyond the thirty-year period (1.0 trillion cubic feet) results in a total of some 38.5 trillion cubic feet of gas available from present sources. If two years growth of gas reserves at the long-term growth rate of 2.5 trillion cubic feet per year is added to this, the total reserve available is some 43.5 trillion cubic feet.

The use of three-quarters of the reserves beyond economic reach represents no change in principle but only a revision in the fraction used from the most recent Board reports wherein one-half of these reserves were relied upon. The change results because of a recently completed detailed review of the reserves now considered beyond economic reach,

having in mind the magnitude of each reserve, its location, the nearness of pipe lines, and the expected development in drilling and in transportation facilities. On the basis of this review, the Board believes that at least three-quarters of the reserves now considered beyond economic reach will be supplying a market within thirty years.

The Board has previously estimated that some 18.0 trillion cubic feet of gas will be needed to meet Alberta's long-term requirements. This, added to the 21.3 trillion cubic feet required to meet the existing permit commitments (from Table D-5) gives a total required reserve of some 39.3 trillion cubic feet. Subtracting 39.3 trillion cubic feet from the available reserves of 43.5 trillion cubic feet, results in a surplus of some 4.2 trillion cubic feet. After the expiry dates of the existing permits, an additional 1.9 trillion cubic feet of gas will be released from terminal year peak day protection, resulting in an overall surplus of some 6.1 trillion cubic feet.

The surplus calculation using the modified method which has been discussed in detail earlier in this report is illustrated in Tables D-6 and D-7. Table D-6 presents the surplus calculation using the data submitted by Trans-Canada at the hearing and Table D-7 presents the surplus calculation using the Board's reserve and requirement estimates. In the preparation of Table D-6 some of the figures shown are the Board's interpretation of the Trans-Canada submission and in

other instances adjustments have been made to fit the Trans-Canada figures to the modified method of calculation adopted by the Board.

Table D-7 shows that the Board's estimate of contractable reserves, the reserves within economic reach (37.2 trillion cubic feet) less the deferred reserves (5.2 trillion cubic feet), totals some 32.0 trillion cubic feet. The contractable requirements include the 6.6 trillion cubic feet now connected to supply Alberta's requirements (thirty times the requirements of the first year of the period under study would result in a lesser contractable requirement of 6.0 trillion cubic feet), and 21.3 trillion cubic feet to meet the existing permit commitments. A comparison of the contractable reserves and contractable requirements results in a contractable surplus of 4.1 trillion cubic feet. The table also shows that the remaining Alberta requirements total some 11.4 trillion cubic feet. These are made up of some 7.0 trillion cubic feet which the Board believes will have to be delivered during the thirty-year period and some 4.4 trillion cubic feet which the Board estimates will be necessary to provide for the thirtieth year peak day. The remaining and future reserves available to meet these Alberta requirements are shown to total some 11.5 trillion cubic feet. These are made up of 4.2 trillion cubic feet of deferred gas which the Board believes will be produced within the thirty-year period, some 2.3 trillion cubic feet of reserves now beyond economic reach but which the Board believes will be

within economic reach within thirty years, and 5.0 trillion cubic feet of future reserves reflecting two years growth at the long-term growth rate of 2.5 trillion cubic feet per year. A comparison of the remaining and future reserves to the remaining requirements results in a future surplus of 0.1 trillion cubic feet. This future surplus, combined with the contractable surplus, gives an overall surplus of 4.2 trillion cubic feet before the release of the 1.9 trillion cubic feet of cushion gas included in the permit requirements. After the expiry dates of the permits and the release of the cushion gas, the overall surplus will total some 6.1 trillion cubic feet. A comparison of Tables D-5 and D-7 indicates that the overall surplus as determined by the Board from the modified method of calculation is identical to the surplus arrived at under the previous method. This is because the modified method does not change either the requirements or reserves but rather introduces categories within the requirements and reserves, and also because the Board has included in its modified surplus calculations only two years growth of gas reserves.

A comparison of Tables D-6 and D-7 show that the contractable surplus as estimated by the Board as of February 28, 1966 is some 4.1 trillion cubic feet, while Trans-Canada estimates the contractable surplus at 5.4 trillion cubic feet as of the same date. The Board's estimate of the future surplus is 0.1 trillion cubic feet while the Trans-Canada estimate is some 1.0 trillion cubic feet. The Board's estimate of the resulting overall

surplus before the release of reserves needed to protect for the permit peak day requirements is 4.2 trillion cubic feet as of February 28, 1966. (This represents an increase of some 3.3 trillion cubic feet since June 30, 1964, the date of the last Board estimate.) The comparable overall surplus as estimated by Trans-Canada is some 1.2 trillion cubic feet greater than the surplus as estimated by the Board. The Board's estimate of the surplus after the release of cushion gas is some 6.1 trillion cubic feet. (This is an increase of 2.6 trillion cubic feet in the twenty-month period June 30, 1964, to February 28, 1966.) This surplus of 6.1 trillion cubic feet compares to one of 7.6 trillion cubic feet as estimated by Trans-Canada.

Trans-Canada's contractable surplus is larger than the Board's because of a slightly higher contractable reserves estimate and a lower contractable requirements estimate. The contractable requirements as estimated by Trans-Canada are lower than the Board's primarily because Trans-Canada has made a cushion gas allowance of only five per cent for permit commitments while the Board's estimate of cushion gas has been determined on the basis of deliverability schedules and the formula approach. Trans-Canada's future surplus is greater than the Board's primarily because the Board has increased its estimate of Alberta requirements (as is discussed in Appendix C) since its OGCB Report 64-11 from which Trans-Canada dopted its estimate of requirements.

TABLE D-1

RESERVES NOW SUPPLYING ALBERTA'S REQUIREMENTS FOR GAS

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

FIELD	MARKETABLE GAS AT FEBRUARY 28, 1966 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
MAJOR RESERVES		
BEAVERHILL LAKE - FORT SASKATCHEWAN	423	0.8
BOW ISLAND AND FOREMOST	41	0.9
CARBON	122	1.5
FAIRYDELL-BON ACCORD	101	0.7
JUMPING POUND, JUMPING POUND WEST AND SARCEE	1206	6.6
MEDICINE HAT	140	3.7
MORINVILLE AND ST. ALBERT-BIG LAKE	141	1.5
OKOTOKS	118	9.3
TURNER VALLEY	228	6.0
VIKING-KINSELLA	429	1.7
WAYNE-ROSEDALE AND REDLAND	179	1.3
WESTLOCK	243	1.2
WORSLEY	150	0.8
TOTAL	3521	
WEIGHTED AVERAGE		1.8
OIL FIELD GAS		
ACHESON	17	
BONNIE GLEN	270	
CAMPBELL-NAMAO	17	
FENN-BIG VALLEY AND STETTLER	62	
GLEN PARK	10	
JUDY CREEK	249	
LEDUC-WOODBEND	49	
PEMBINA	1158	
REDWATER	49	
SAMSON	8	

(CONTINUED)

TABLE D-1 (CONTINUED)

FIELD	MARKETABLE GAS AT FEBRUARY 28, 1966 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
<u>OIL FIELD GAS</u> (CONT'D)		
SIMONETTE	83	
STURGEON LAKE SOUTH	79	
SWAN HILLS	260	
SWAN HILLS SOUTH	168	
VIRGINIA HILLS	36	
WIZARD LAKE	112	
TOTAL	2627	
WEIGHTED AVERAGE		13.9
<u>SMALL RESERVES PLUS RESERVES SUPPLYING SMALL UTILITIES</u>		
ACHESON	25	
ALDERSON	17	
ALEXANDER	12	
ATHABASCA	7	
ATHABASCA EAST	1	
ATIM	3	
BANTRY	33	
BONNIE GLEN	1	
BONNYVILLE	2	
BROOKS	4	
CALAIS	8	
CASTOR	6	
COLD LAKE	1	
CRAIG LAKE	7	
DOWLING LAKE	3	
DUVERNAY	1	
EDWAND	7	
ELLERSLIE	1	
ELK POINT	1	

(CONTINUED)

TABLE D-1 (CONTINUED)

FIELD	MARKETABLE GAS AT FEBRUARY 28, 1966 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
<u>SMALL RESERVES PLUS RESERVES SUPPLYING SMALL UTILITIES</u> (CONT'D)		
ETZIKOM	30	
EXCELSIOR	5	
FORT KENT	3	
GLEN PARK	5	
HAIRY HILL	15	
HAMELIN CREEK	13	
HANNA	6	
HEART RIVER	4	
HOLMBERG	21	
KNOPCIK	12	
LAC LA BICHE	14	
LEAHURST	34	
LINDBERGH	11	
LLOYDMINSTER	2	
MURIEL LAKE	6	
NORMANDVILLE	24	
OBERLIN	1	
REDWATER	9	
RYCROFT	10	
ST. PAUL	1	
STRATHMORE	10	
WATTS	2	
WHITELAW	20	
WILDMERE	18	
WILLINGDON	14	
WIZARD LAKE	1	
WOKING	4	
TOTAL	435	
WEIGHTED AVERAGE		2.5
TOTAL RESERVES CONNECTED AND SUPPLYING REQUIREMENTS	6583	
WEIGHTED AVERAGE RESERVE-DELIVERY RATIO		3.5

TABLE D-2

AVERAGE RESERVE-DELIVERY RATIO FOR ALL

RESERVES IN THE PROVINCE

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

	MARKETABLE RESERVE AT FEBRUARY 28, 1966 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
RESERVES NOW SUPPLYING ALBERTA'S REQUIREMENTS (SEE TABLE D-1)	6583	3.5
FIELDS INCLUDED IN PERMITS (SEE TABLE D-3)	22171	2.0
FIELDS APPLIED FOR BY TRANS-CANADA PIPE LINES LIMITED (SEE TABLE E-1)	2470	1.6
REMAINING ESTABLISHED RESERVES[1]	9074	3.5
TOTAL RECOVERABLE RESERVES IN THE PROVINCE	40298	
WEIGHTED AVERAGE RESERVE-DELIVERY RATIO		2.4

(1) INCLUDES DEFERRED RESERVES AND RESERVES NOW CONSIDERED BEYOND ECONOMIC REACH.

TABLE D-3

MARKETABLE RESERVES AVAILABLE IN THE FIELDS INCLUDED IN PERMITS

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

ALBERTA AND SOUTHERN GAS CO. LTD.

FIELD	MARKETABLE RESERVE AT FEBRUARY 28, 1966 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
BERLAND RIVER	300	1.2
BIGSTONE	285	5.1
BRAZEAU RIVER	333	5.7
BURNT TIMBER	270	9.7
CAROLINE	44	2.1
CARSON CREEK	DEFERRED	-
CARSON CREEK NORTH	DEFERRED	-
CROSSFIELD	772	2.5
FERRIER	6	3.0
FOX CREEK	12	1.1
FOX CREEK NORTH	44	4.5
FOX CREEK WEST	31	3.2
HARMATTAN-ELKTON	187	1.7
HOMEGLEN-RIMBEY	155	0.8
HUNTER VALLEY	54	1.9
KAYBOB	471	2.0
LEAFLAND NORTH	12	3.0
MARLBORO	41	3.0
MINNEHIK-BUCK LAKE	419	3.0
PEMBINA	205	4.6
PINE NORTH-WEST	105	3.0
SUNDRE	43	10.0
SYLVAN LAKE	7	2.1
WATERTON	1217	4.0
WESTEROSE	77	10.0

(CONTINUED)

TABLE D-3 (CONTINUED)

ALBERTA AND SOUTHERN GAS CO. LTD. (CONT.) FIELD	MARKETABLE RESERVE AT FEBRUARY 28, 1966 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
WESTEROSE SOUTH	641	0.5
WILDCAT HILLS	512	8.1
WILDHORSE CREEK	94	4.5
WILLESDEN GREEN	94	8.0
WILSON CREEK	38	1.0
WINDFALL AND PINE CREEK	825	1.6
TOTAL	7294	
WEIGHTED AVERAGE		1.8
CANADIAN-MONTANA PIPELINE COMPANY		
ADEN	15	
BLACK BUTTE	49	
COMREY	13	
MANYBERRIES	6	
PAKOWKI LAKE	5	
PENDANT D'OREILLE	93	
SMITH COULEE	17	
TOTAL	198	
WEIGHTED AVERAGE		3.0
TRANS-CANADA PIPE LINES LIMITED		
ATLEE-BUFFALO	133	4.1
BINDLOSS	295	3.3
CARSTAIRS	776	2.5
CESSFORD	1155	3.0
CHIGWELL	57	2.1
CONNORSVILLE	60	3.6
COUNTESS	152	2.1
CROSSFIELD EAST	642	1.5
EDSON	1814	2.2
ENCHANT	31	3.0
ERSKINE	45	-

(CONTINUED)

TABLE D-3 (CONTINUED)

TRANS-CANADA PIPE LINES LIMITED (CONT.)

FIELD	MARKETABLE RESERVE AT FEBRUARY 28, 1966 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
FENN-BIG VALLEY	-	-
FENN WEST	7	2.3
GILBY	748	2.0
HACKETT	52	3.5
HAMILTON LAKE	-	-
HARMATTAN-ELKTON	41	1.3
HOMEGLEN-RIMBEY	529	0.8
HUSSAR	522	1.8
INNISFAIL	86	12.0
KESSLER	59	2.5
LONE PINE CREEK	172	7.7
MEDICINE RIVER	251	3.4
MEDICINE HAT	370	5.5
MINNEHIK-BUCK LAKE	-	-
NEVIS	640	2.3
OLDS	248	4.2
OYEN	37	2.0
PINCHER CREEK	312	8.8
PREVO	36	4.7
PRINCESS	140	3.0
PROVOST	484	2.5
RETLAW	46	1.6
RICH	13	1.5
SEDALIA	98	7.8
SIBBALD	26	3.0
STANDARD	20	6.2
STETTLER	-	-
SYLVAN LAKE	494	2.0
THREE HILLS CREEK	195	4.7
VERGER	69	0.7
WAYNE-ROSEDALE	216	2.5
WESTEROSE SOUTH	486	0.5

(CONTINUED)

TABLE D-3 (CONTINUED)

FIELD	MARKETABLE RESERVE AT FEBRUARY 28, 1966 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
TRANS-CANADA PIPE LINES LIMITED (CONT.)		
WIMBORNE	227	1.0
WOOD RIVER	32	2.5
TOTAL	11816	
WEIGHTED AVERAGE		2.0
WESTCOAST TRANSMISSION COMPANY LIMITED (SOUTHERN ALBERTA)		
CROSSFIELD	1382	3.0
SAVANNA CREEK	388	20.0
TOTAL	1770	
WEIGHTED AVERAGE		3.7
WESTCOAST TRANSMISSION COMPANY LIMITED (PEACE RIVER)		
BOUNDARY LAKE SOUTH	43	1.3
BRAEBURN	67	5.1
BURNT RIVER	3	2.0
GORDONDALE	21	3.1
POUCE COUPE	49	2.8
POUCE COUPE SOUTH	36	3.0
SADDLE HILLS	50	5.0
WORSLEY	53	0.8
TOTAL	322	
WEIGHTED AVERAGE		2.1
OTHERS		
ANTELOPE	21	4.9
ESTHER	32	3.7
HALLIDAY	4	1.5
MEDICINE HAT	673	3.7
RICHDALE	18	3.5
WILDUNN CREEK	23	2.0
TOTAL	771	
WEIGHTED AVERAGE		3.6
TOTAL (ALL FIELDS)	22,171	
WEIGHTED AVERAGE (ALL FIELDS)		2.0

TABLE D-4

RESERVES REQUIRED TO MEET PRESENT PERMIT COMMITMENTS

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	REMAINING PERMIT COMMITMENT									EXCESS IN PERMIT FIELDS	
PERMITTEE	TOTAL BCF	MAXIMUM DAY MMCF	TERMINAL DATE OF PERMIT	RESERVE IN PERMIT FIELDS BCF	RESERVE-DELIVERY RATIO OF PERMIT FIELDS BCF/MMCFD	COMPOSITE CORRECTION FACTOR	MARKETABLE GAS IN PLACE REQUIRED TO MEET TERMINAL PEAK DAY BCF	MARKETABLE GAS REQUIRED TO MEET TERMINAL PEAK DAY BCF	TOTAL MARKETABLE GAS TO MEET PERMIT COMMITMENT BCF	BEFORE TERMINAL DATE BCF	AFTER TERMINAL DATE BCF
ALBERTA AND SOUTHERN GAS CO. LTD.	6167	795	31/10/89	7294	1.8	2.2	3148	1471	7638	-344	1127
	5747(1)	795		7294	1.8	2.2	3148	1547	7294	-	1547
	420	-		1547	-	-	-	1127	420	-	1127
CANADIAN-MONTANA PIPELINE COMPANY	198	99	14/ 3/86	198	-	-	-	-	198	-	-
TRANS-CANADA PIPE LINES LIMITED	10933	1643	31/10/89	11816	-	-	-	-	10933	883	883
WESTCOAST TRANSMISSION COMPANY LIMITED (SOUTHERN ALBERTA)	989	177	29/ 2/84	1770	3.7	1.5	982	726	1715	55	781
WESTCOAST TRANSMISSION COMPANY LIMITED (PEACE RIVER)	322	-	31/ 2/79	322	-	-	-	-	322	-	-
OTHERS	753	181		771	-	-	-	18	771	-	18
TOTALS	19362	2895		22171				1871	21233	938	2809
ROUNDED TOTALS	19400	2900		22200				1900	21300	900	2800

(1) ESTIMATED WITHDRAWAL TO WHICH THE MAXIMUM PERMISSIVE RATE COULD BE MAINTAINED.

TABLE D-5

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS

AS OF FEBRUARY 28, 1966

DETERMINED IN ACCORDANCE WITH BOARD PREVIOUS METHOD

(All Volumes In Trillions Of Cubic Feet At 1000 Btu Per Cubic Foot)

ESTABLISHED RESERVES

Now Considered Within Economic Reach	37.2		
From Reserves Now Considered Beyond Economic Reach	2.3		
Less: Deferred Beyond 30 Years	1.0		
Total Reserves From Present Sources		38.5	
From 2 Years Trends		5.0	
Total Reserves Available			43.5

RESERVES NEEDED TO MEET ALBERTA REQUIREMENTS AND PERMIT COMMITMENTS

ALBERTA REQUIREMENTS			
Now Connected And Supplying Requirements	6.6		
Required From Other Sources	7.0		
Required From Other Sources To Meet Thirtieth Year Peak Day	4.4		
Total For Alberta Requirements		18.0	
PRESENT PERMIT COMMITMENTS			
Required To Meet Commitments	19.4		
Required To Meet Terminal Year Peak Day	1.9		
Total Required To Meet Permit Commitments		21.3	
Reserves Required To Meet Alberta Requirements And Present Permit Commitments		39.3	
Less: Reserves Released From Peak Protection After Expiry Of Permits		1.9	
Total Reserves Needed To Meet Requirements And Commitments			37.4
Surplus Before Release Of Reserves Required To Protect Peak Day In Permits			4.2
Surplus After Release Of Reserves Required To Protect Peak Day In Permits			6.1

TABLE D-6

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS

AS OF FEBRUARY 28, 1966

DETERMINED IN ACCORDANCE WITH BOARD MODIFIED METHOD

AS ESTIMATED BY TRANS-CANADA

(ALL VOLUMES IN TRILLIONS OF CUBIC FEET AT 1000 BTU PER CUBIC FOOT)

CONTRACTABLE RESERVES				
Now Considered Within Economic Reach			37.4	
Less: Deferred			4.9	
Total Contractable Reserves				32.5
CONTRACTABLE REQUIREMENTS				
Contractable Alberta Requirements			6.4	
Permit Requirements - To Meet Commitments		19.5		
To Meet Terminal Year Peak Day		1.2		
			20.7	
Total Contractable Requirements				27.1
CONTRACTABLE SURPLUS				5.4
REMAINING REQUIREMENTS				
Total Alberta Requirements For Delivery	11.2			
Less: Deliveries From Contractable Reserves	4.8			
Deliveries Required From Other Sources		6.4		
Total Alberta Requirements For Delivery And Thirtieth Year Peak Day	17.4			
Less: Contractable Alberta Requirements	6.4			
Deliveries Required From Other Sources	6.4			
Required From Other Sources To Meet Thirtieth Year Peak Day		4.6		
Total Remaining Requirements			11.0	
REMAINING AND FUTURE RESERVES				
From Deferred Gas Available Within 30 Years		4.4		
From Reserves Now Considered Beyond Economic Reach		2.4		
From 2 Years Trends		5.2		
Total Remaining And Future Reserves			12.0	
FUTURE SURPLUS				1.0
OVERALL SURPLUS				
Before Release Of Reserves Required To Protect Peak Day In Permits				6.4
After Release Of Reserves Required To Protect Peak Day In Permits				7.6

TABLE D-7

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS

AS OF FEBRUARY 28, 1966

DETERMINED IN ACCORDANCE WITH BOARD MODIFIED METHOD AS ESTIMATED BY THE BOARD

(All Volumes In Trillions Of Cubic Feet At 1000 Btu Per Cubic Foot)

CONTRACTABLE RESERVES				
Now Considered Within Economic Reach			37.2	
Less: Deferred			5.2	
Total Contractable Reserves				32.0
CONTRACTABLE REQUIREMENTS				
Contractable Alberta Requirements			6.6	
Permit Requirements - To Meet Commitments		19.4		
- To Meet Terminal Year Peak Day		1.9		
			21.3	
Total Contractable Requirements				27.9
CONTRACTABLE SURPLUS				4.1
REMAINING REQUIREMENTS				
Total Alberta Requirements For Delivery	11.9			
Less: Deliveries From Contractable Reserves	4.9			
Deliveries Required From Other Sources		7.0		
Total Alberta Requirements For Delivery And Thirtieth Year Peak Day	18.0			
Less: Contractable Alberta Requirements	6.6			
Delivieries Required From Other Sources	7.0			
Required From Other Sources To Meet Thirtieth Year Peak Day		4.4		
Total Remaining Requirements			11.4	
REMAINING AND FUTURE RESERVES				
From Deferred Gas Available Within 30 Years		4.2		
From Reserves Now Considered Beyond Economic Reach		2.3		
From 2 Years Trends		5.0		
Total Remaining And Future Reserves			11.5	
FUTURE SURPLUS				0.1
OVERALL SURPLUS				
Before Release Of Reserves Required To Protect Peak Day In Permits				4.2
After Release Of Reserves Required To Protect Peak Day In Permits				6.1

APPENDIX E

THE APPLICANT'S REQUEST FOR AUTHORIZATION FOR THE REMOVAL OF ADDITIONAL QUANTITIES OF GAS AND THE SURPLUS WHICH WOULD RESULT IF THE REQUEST WERE GRANTED

Trans-Canada is now authorized under it's permit to remove from the Province 12,080 billion cubic feet of gas, of which some 1,766 billion cubic feet have been removed to February 28, 1966. It has requested an increase of the authorized quantity of 12,080 billion cubic feet to a total of 15,000 billion cubic feet of gas at a maximum daily rate of 1,995 million cubic feet from the fields included in it's existing permit and from some thirty new fields. For convenience in the study of the meeting of the requested volumes, the Board has converted the quantities to the basis of 1000 Btu's per cubic foot. The equivalent requested volumes become 15,874 billion cubic feet and 2,111 million cubic feet per day. (All volumes subsequently referred to in this Appendix will be on the basis of 1000 Btu's per cubic foot).

Trans-Canada has in effect requested an increase of it's remaining authorized withdrawals from 10,933 to 14,006 billion cubic feet (15,874 minus 1,868 = 14,006) as of February 28, 1966.

Table E-1 lists the additional fields from which Trans-Canada proposed to remove gas from the Province. The table also shows the Board's current estimate of the remaining reserves of marketable gas and the reserve-delivery ratio for each of these fields.

The results of the Board's analysis with respect to the

meeting of the permit commitments and the Trans-Canada application is presented in Table E-2 which is identical in form to the previously discussed Table D-4. In fact, the only change has been to replace the Trans-Canada entry with a new entry reflecting the additional quantities applied for and the reserves in the fields from which Trans-Canada proposes to remove gas.

Columns 1 and 2 of Table E-2 show the total remaining permit commitment and the maximum day authorized for each of the permits (in the case of Trans-Canada, the quantities applied for are shown). Column 3 is the expiry dates of the permits. The Board's present estimate of the total reserves in the fields included in the existing permits, and in the case of the Trans-Canada permit, in the new fields applied for, are shown in column 4. Column 5 shows the Board's estimates of the average reserve-delivery ratio for those reserves shown in column 4. Each of these quantities have been obtained from Tables D-3 and E-1. Column 6 shows the composite correction factors determined from earlier detailed deliverability schedules. Column 7 presents the quantity of marketable gas in place that would be required to meet the peak day for each of the permits for which in the Board's opinion cushion gas should be provided. Column 8 shows the marketable gas equivalent of column 7 and is obtained by deducting from the quantities shown in column 7 the marketable gas equivalent of the gas that will remain in the reservoirs at abandonment. The total marketable gas required to satisfy

the permit commitments, including Trans-Canada's application is shown in column 9 and is obtained by summing the quantities shown in columns 1 and 8. Columns 10 and 11 show the amounts of gas excess to the permits before and after the expiry date of each of the permits.

It may be seen from the Trans-Canada entry in Table E-2 that the remaining requested volume of 14,006 billion cubic feet is slightly less than the total reserves available of some 14,286 billion cubic feet. Consequently, the Board is of the opinion that the entire amount applied for may be included in the quantity approved for removal from the Province, but no assurance can be given that the gas can be produced during the term of the permit at the requested maximum daily rate.

Since the permits for the removal of gas from the Province are issued on an "as is" basis, rather than a 1000 Btu basis, the remaining requested volume previously referred to must be converted to the basis of 14.65 pounds per square inch absolute and sixty degrees Fahrenheit. The volume of 14,006 billion cubic feet is equivalent to some 13,234 billion cubic feet on an as is basis. When the 1,766 billion cubic feet removed to February 28, 1966 is added to the remaining volume, the initial quantity authorized by the permit becomes 15,000 billion cubic feet.

Table E-2 shows that with the inclusion of the Trans-Canada application, the remaining permit commitments would total some 22.4 trillion cubic feet and the reserves required to meet

these commitments would total some 24.3 trillion cubic feet.

As in the case where only the existing permit commitments were considered (Appendix D), the Board has determined the gas surplus to Alberta's requirements and the permit commitments including Trans-Canada's application using both the previous method and the newly adopted modified method of calculating the surplus. The two methods are illustrated in Tables E-3 and E-4, respectively. A comparison of the tables shows that the overall surplus resulting from the two methods of calculation are identical. Again this is because the modified method does not change either the requirements or reserves, but rather categorizes them, and also because only two years growth of gas reserves have been included in the modified calculation.

Most of the figures used in the preparation of Tables E-3 and E-4 have been taken directly from Tables D-5 and D-7. The only adjustments made were to Alberta's requirements which have been increased to include the Trunk Line pipe line fuel and the shrinkage that would be associated with the additional quantities of gas applied for by Trans-Canada and to the reserves required to meet the existing and the applied for permit commitments which have been taken from Table E-2.

Table E-4 shows that should the additional volume applied for by Trans-Canada be authorized for removal from the Province, the contractable surplus as estimated by the Board would be some 1.1 trillion cubic feet. The table also shows that the remaining requirements would be equal to the remaining and future reserves.

This results in an overall surplus of 1.1 trillion cubic feet before the release of reserves required for the protection of the peak day quantities specified in the permits. After the expiry dates for the permits, an additional 1.9 trillion cubic feet of gas would be released from terminal year peak day protection increasing the surplus to some 3.0 trillion cubic feet.

TABLE E-1

MARKETABLE RESERVES IN FIELDS APPLIED FOR BY
TRANS-CANADA PIPE LINES LIMITED

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

FIELD	MARKETABLE RESERVE AT FEBRUARY 28, 1966 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
ABEE	6	0.7
ALDERSON	206	6.4
BAPTISTE	12	3.3
BASHAW	33	1.0
BELLIS	40	1.3
BOYLE	11	0.7
CALLING LAKE	37	3.1
CAROLINE	117	2.4
CRAIGEND	178	6.3
CROSSFIELD	336	0.6
DRUMHELLER	48	0.6
EQUITY	25	3.3
FIGURE LAKE	33	1.2
FRANCIS	9	3.0
GARRINGTON	10	3.0
GHOST PINE	135	5.0
HARMATTAN EAST	223	8.3
LITTLE BOW	15	0.4
LONG COULEE	14	0.2
MALMO	39	1.0
MARTEN HILLS	690	2.1
ROWLEY	65	1.7
SIEU LAKE	14	3.8
SUNDRE	16	1.4
SUNNYNOOK	10	1.2
SWALWELL	37	5.5

(CONTINUED)

TABLE E-1 (CONTINUED)

FIELD	MARKETABLE RESERVE AT FEBRUARY 28, 1966 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
THORHILD	10	1.7
TROCHU	5	1.0
VULCAN	35	1.8
WINTERING HILLS	61	2.5
TOTAL	2470	
WEIGHTED AVERAGE		1.6

TABLE E-2

RESERVES REQUIRED TO MEET PRESENT PERMIT COMMITMENTS INCLUDING TRANS-CANADA APPLICATION

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	REMAINING PERMIT COMMITMENT									EXCESS GAS IN PERMIT FIELDS	
PERMITTEE	TOTAL BCF	MAXIMUM DAY MMCF	TERMINAL DATE OF PERMIT	RESERVE IN PERMIT FIELDS BCF	RESERVE-DELIVERY RATIO OF PERMIT FIELDS BCF/MMCFD	COMPOSITE CORRECTION FACTOR	MARKETABLE GAS IN PLACE REQUIRED TO MEET TERMINAL PEAK DAY BCF	MARKETABLE GAS REQUIRED TO MEET TERMINAL PEAK DAY BCF	TOTAL MARKETABLE GAS TO MEET PERMIT COMMITMENT BCF	BEFORE TERMINAL DATE BCF	AFTER TERMINAL DATE BCF
ALBERTA AND SOUTHERN GAS CO. LTD.	6167	795	31/10/89	7294	1.8	2.2	3148	1471	7638	-344	1127
	5747 (1)	795		7294	1.8	2.2	3148	1547	7294	-	1547
	420	-		1547	-	-	-	1127	420	-	1127
CANADIAN-MONTANA PIPELINE COMPANY	198	99	14/3/86	198	-	-	-	-	198	-	-
TRANS-CANADA PIPE LINES LIMITED	14006	2111	31/10/90	14286	-	-	-	-	14006	280	280
WESTCOAST TRANSMISSION COMPANY LIMITED (SOUTHERN ALBERTA)	989	177	29/2/84	1770	3.7	1.5	982	726	1715	55	781
WESTCOAST TRANSMISSION COMPANY LIMITED (PEACE RIVER)	322	-	31/2/79	322	-	-	-	-	322	-	-
OTHERS	753	181		771	-	-	-	-18	771	-	18
TOTALS	22435	3363		24641				1871	24306	335	2206
ROUNDED TOTALS	22400	3400		24600				1900	24300	300	2200

(1) ESTIMATED WITHDRAWAL TO WHICH THE MAXIMUM PERMISSIVE RATE COULD BE MAINTAINED.

TABLE E-3

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS
AS OF FEBRUARY 28, 1966 IF TRANS-CANADA APPLICATION IS GRANTED
DETERMINED IN ACCORDANCE WITH BOARD PREVIOUS METHOD

(All Volumes In Trillions of Cubic Feet At 1000 Btu Per Cubic Foot)

ESTABLISHED RESERVES			
Now Considered Within Economic Reach	37.2		
From Reserves Now Considered Beyond Economic Reach	2.3		
Less: Deferred Beyond 30 Years	1.0		
Total Reserves From Present Sources		38.5	
From 2 Years Trends		5.0	
Total Reserves Available			43.5
RESERVES NEEDED TO MEET ALBERTA REQUIREMENTS AND PERMIT COMMITMENTS			
ALBERTA REQUIREMENTS			
Now Connected And Supplying Requirements	6.6		
Required From Other Sources	7.1		
Required From Other Sources to Meet Thirtieth Year Peak Day	4.4		
Total For Alberta Requirements		18.1	
PRESENT PERMIT COMMITMENTS			
Required To Meet Commitments	22.4		
Required To Meet Terminal Year Peak Day	1.9		
Total Required To Meet Permit Commitments		24.3	
Reserves Required To Meet Alberta Requirements And Present Permit Commitments		42.4	
Less: Reserves Released From Peak Protection After Expiry Of Permits		1.9	
Total Reserves Needed To Meet Requirements And Commitments			40.5
Surplus Before Release Of Reserves Required To Protect Peak Day In Permits			1.1
Surplus After Release Of Reserves Required To Protect Peak Day In Permits			3.0

TABLE E-4

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND PERMIT COMMITMENTS
AS OF FEBRUARY 28, 1966 IF TRANS-CANADA APPLICATION IS GRANTED
DETERMINED IN ACCORDANCE WITH BOARD MODIFIED METHOD

(ALL VOLUMES IN TRILLIONS OF CUBIC FEET AT 1000 BTU PER CUBIC FOOT)

CONTRACTABLE RESERVES				
Now Considered Within Economic Reach			37.2	
Less Deferred			5.2	
Total Contractable Reserves				32.0
CONTRACTABLE REQUIREMENTS				
Contractable Alberta Requirements			6.6	
Permit Requirements - To Meet Commitments		22.4		
To Meet Terminal Year Peak Day		1.9		
			24.3	
Total Contractable Requirements				30.9
CONTRACTABLE SURPLUS				1.1
REMAINING REQUIREMENTS				
Total Alberta Requirements For Delivery	12.0			
Less Deliveries From Contractable Reserves	4.9			
Deliveries Required From Other Sources		7.1		
Total Alberta Requirements For Delivery And Thirtieth Year Peak Day	18.1			
Less: Contractable Alberta Requirements	6.6			
Deliveries Required From Other Sources	7.1			
Required From Other Sources To Meet Thirtieth Year Peak Day		4.4		
Total Remaining Requirements			11.5	
REMAINING AND FUTURE RESERVES				
From Deferred Gas Available Within 30 Years		4.2		
From Reserves Now Considered Beyond Economic Reach		2.3		
From 2 Years Trends		5.0		
Total Remaining And Future Reserves			11.5	
FUTURE SURPLUS				0.0
OVERALL SURPLUS				
Before Release Of Reserves Required To Protect Peak Day In Permits				1.1
After Release Of Reserves Required To Protect Peak Day In Permits				3.0

APPENDIX F

IN THE MATTER of The Gas Resources Preservation Act, 1956, being chapter 19 of the Statutes of Alberta, 1956; and

IN THE MATTER of a Permit to Trans-Canada Pipe Lines Limited authorizing the removal of gas from the Province.

AMENDMENT OF PERMIT NO. TC 64-6

The Oil and Gas Conservation Board, pursuant to section 12 of The Gas Resources Preservation Act, 1956, being chapter 19 of the Statutes of Alberta, 1956, having publicly heard the application of the Permittee for amendment of the permit, at the City of Calgary, in the Province of Alberta, at a hearing on March 10 and 11, 1966, having regard to its own knowledge and responsibility under the Act, and the Lieutenant Governor in Council having given his approval by Order in Council dated and numbered O.C. , hereby orders as follows:

1. Permit No. TC 64-6, dated December 1, 1964, granted under The Gas Resources Preservation Act, 1956, to Trans-Canada Pipe Lines Limited, is amended.

2. Clause 1 of the terms and conditions of the Permit is amended by striking out the numeral "1989" and by substituting the numeral "1990".

3. Clause 2 of the terms and conditions of the Permit is struck out and the following is substituted:

2. The quantity of gas that may be removed from the Province pursuant to this Permit shall not exceed

(a) during the term of the Permit and together with gas removed under Permits numbered TC 54-1, TC 59-2, TC 60-3, TC 60-4 and TC 64-5, 15,000,000,000,000 cubic feet, nor

(b) during any consecutive twenty-four hour period or any consecutive twelve-month period ending October 31, rates limited by field productivity and good engineering practice, but in a twenty-four hour period such rates shall not exceed 1,995,000,000 cubic feet and in a twelve-month period such rates shall not exceed 665,000,000,000 cubic feet.

4. Clause 4 of the terms and conditions of the Permit is amended as to the list of pools, fields and areas

(a) by striking out the words "Crossfield Cardium Pool" and by substituting the words "Crossfield Field",

(b) by adding to the list the following:

Abee Field

Alderson 2 WS A Pool

Alderson 2 WS B Pool

Alderson Bow Island A Pool

Baptiste Field

Bashaw Field

Bellis Field

Boyle Field

Calling Lake Field

Caroline Viking A Pool

Caroline Viking D Pool

Caroline Viking E Pool

Caroline Basal Mannville A Pool

Craigend Field

Drumheller Field

Equity Field

Figure Lake Field

Francis Field

Garrington Viking A Pool

Garrington Viking B Pool

Garrington Mannville A Pool

Garrington Leduc A Pool

Ghost Pine Field

Harmattan East Field

Little Bow Field

Long Coulee Field

Malmo Leduc B Pool

Marten Hills Field

Rowley Field

Seiu Lake Field

Sundre Viking A Pool

Sundre Basal Mannville A Pool

Sundre Basal Mannville B Pool

Sunnynook Field

Swalwell Field

Thorhild Field

Trochu Field

Vulcan Field

Wintering Hills Field

5. Clause 6 of the terms and conditions of the Permit is amended

(a) by striking out the word "interconnection" and by substituting the word "interconnections",

(b) by adding at the end thereof the words "and in the North-east quarter of Section 11, Township 38, Range 1, West of the 4th Meridian".

MADE at the City of Calgary, in the Province of Alberta, this day of A.D. 1966.

OIL AND GAS CONSERVATION BOARD

G. W. Govier

Chairman

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[illegible] Province of Alberta,

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THE ENERGY RESOURCES CONSERVATION BOARD

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